Government Leadership

Regional Energy Transition Accelerator (RETA)

Northland – Phase One Report

March 2024

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

Ko te pae tawhiti ka whaia kia tata!

Ko te pae tata ka whakamau ai kia tīna!

Ko tā tātou he whaiwhai i te pae tawhiti, e whakatairanga ana i a tātou tikanga haumako, i a tātou tikanga hauora e whakanui nei i te pito mata kei roto i ngā āhuatanga tiaki tangata, tiaki taputapu, tiaki taiao anō hoki.

Mā te mōhio ki te pae tawhiti, arā, ko tā te rautaki a 'Northland Regional Energy Transition Accelerator (RETA),' ka whakatairangihia te whakapaunga kaha me te ara whakawhiti ki ngā rawa whakahou mā ngā hinonga mahitahi me te hōrapahanga o ngā mōhioranga matua.

Ko te pūrongo ka whai ake, e arotahi ana ki ngā whakatakotoranga matua o ngā rawa whakahou i Te Tai Tokerau me te whakaminominohanga i ōna rawa ngahere.

Ko te ngākau whakaiti tēnei e mihi ana ki te whakapeto ngoi a ngā tini rōpū tautoko. Koia nei te tīmatanga o tā tātou pae tata, arā ko te hura i ngā pūmanawatanga i roto i Te Tai Tokerau.

Ko te pae tata ka whakamau ai kia tīna!

1 Foreword

Clean and clever energy use benefits regions and the businesses within them – operations become cheaper and more reliable, increasing productivity, and contributing to better environmental outcomes.

But achieving energy efficiency and fuel switching at scale requires good information, at the right time, alongside strong regional collaboration. This Northland Regional Energy Transition Accelerator (RETA) is designed to help.

The aim of the RETA programme is to develop and share a well-informed, coordinated approach to guide better energy use, prioritisation of renewables, and adoption of new energy solutions – reducing carbon emissions at the same time.

Heat used in manufacturing and in the processing of primary products currently makes up around 25% of our country's energy-related emissions, and so reducing our reliance on fossil fuels – like gas and coal, will have a big impact.

This Northland RETA report is the culmination of the planning phase of the RETA programme. It forecasts and maps regional stationary heat energy demand – at the medium to large end, and renewable energy supply to help make the best asset and infrastructure investments and reduce costs. It also highlights the benefit of aligning decisions made on a regional level.

The data and analysis in this report shows an interesting picture, particularly the opportunity for biofuel and related investment. Northland is a forestry-rich region and could meet most of its future energy demand though biomass as the fuel source. With supply available for neighbouring regions too.

Several businesses in Northland are already undertaking projects or have a low-emissions pathway mapped out with EECA. They are a fantastic example of what can be achieved, and their efforts and willingness to share what they have learned with others has been valuable to this process.

We are proud to have worked closely with Northland Inc, Regional Economic Development Agency, local EDBs Top Energy and Northpower, Transpower, regional forestry companies, wood processors, electricity generators and retailers, and medium to large industrial energy users. A big thank you to these organisations for their input and enthusiasm.

We are looking forward to continuing the discussion as we work together to unlock the region's potential.

Nicki Sutherland
Group Manager Business, EECA

2 Acknowledgements

This RETA project has involved a significant amount of time, resource and input from a variety of organisations. We are especially grateful for the contribution from the following organisations:

- Process heat users throughout the Northland region
- Northland Inc, Regional Economic Development Agency
- Local Electricity Distribution Businesses Top Energy and Northpower
- National grid owner and operator Transpower
- Regional forestry companies
- Regional wood processors
- Electricity generators and retailers

This RETA report is the distillation of individual workstreams delivered by:

- **DETA** – process heat demand-side assessment
- **Forme** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis
- **EnergyLink** – electricity price forecast
- **Wayne Manor Advisory** – report collation, publication and modelling assistance

Arai Te Uru, Northland, New Zealand. Credit Northland NZ.

> *"The availability of biofuel is expected to be higher than the anticipated demand, highlighting the potential for Northland to use biomass locally and export it to neighbouring regions. Coupled with investment in biomass infrastructure, this could see significant economic benefits for the region."*

Nicki Sutherland , Group Manager Business, EECA

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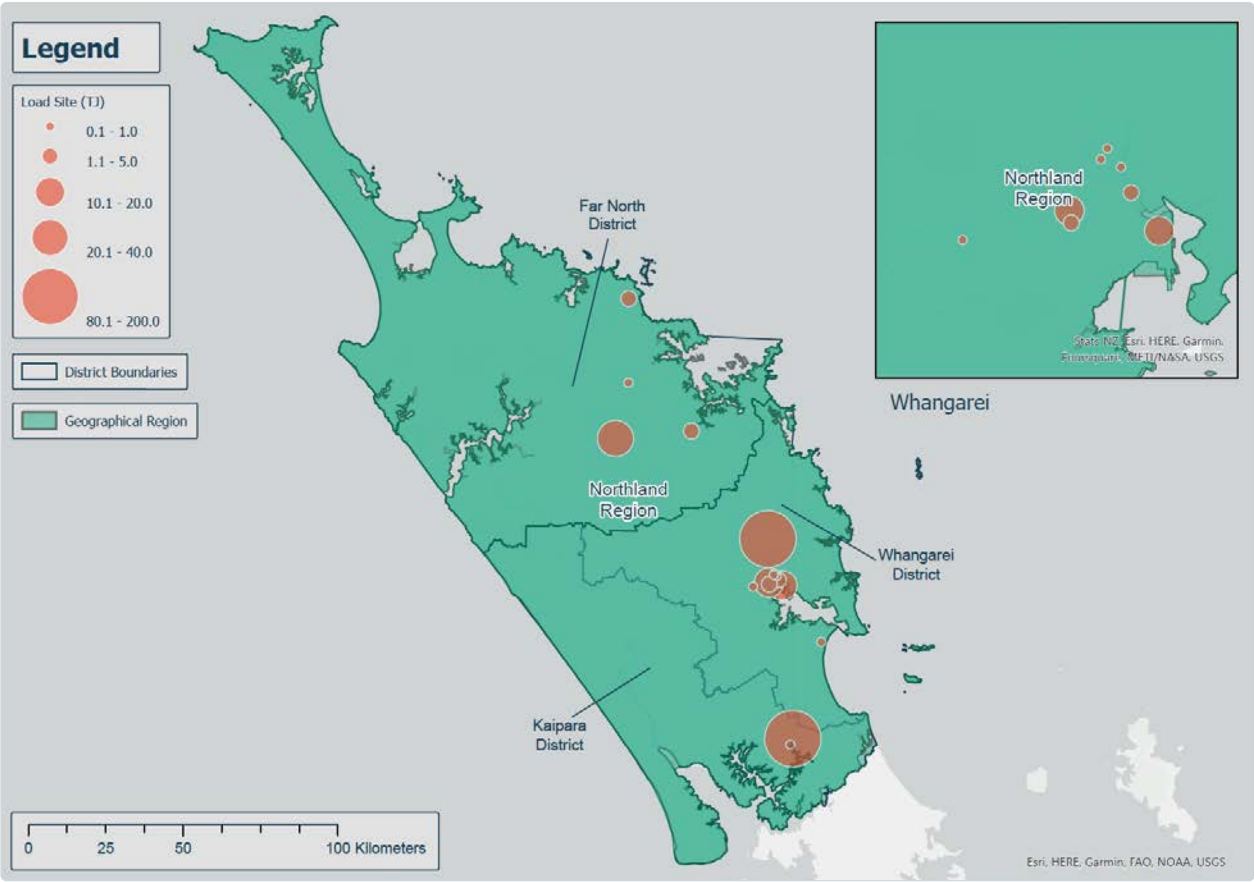
The Northland region is the focus for New Zealand's seventh Regional Energy Transition Accelerator (RETA).

4 Executive summary

This report summarises the results of the planning phase of the Northland Regional Energy Transition Accelerator.

The region covers the area shown in Figure 1.

Figure 1 – Map of area covered by the Northland RETA



The 18 RETA sites covered span the dairy, industrial and commercial[1] sectors. These sites either have fossil-fuelled process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in the Regional Heat Demand Database) or are sites for which EECA (Energy Efficiency and Conservation Authority) has detailed information about their decarbonisation pathway[2]. Together, these sites collectively consume 4,471TJ of process heat energy, primarily in the form of coal, and currently produce 262kt pa of carbon dioxide equivalent (CO_2e) emissions.

1 The commercial sector includes schools, hospitals, and accommodation facilities.

2 For example, process heat equipment details have been captured in an ETA opportunities assessment report.

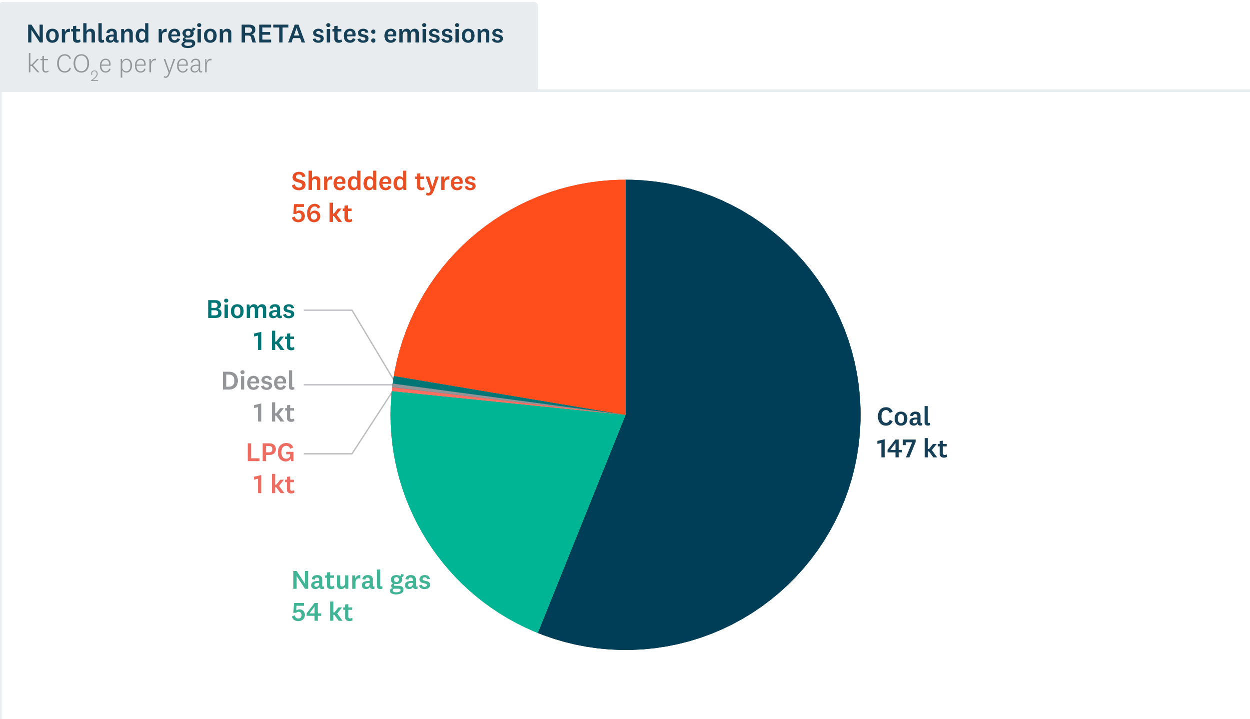
Table 1 – Summary of Northland RETA sites process heat demand and emissions

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Dairy	2	93	264	950	51
Industrial	6	148	960	3,456	208
Commercial	10	16	18	66	4
Total	**18**	**257**	**1,242**	**4,472**	**263**

Only 3,646TJ of this demand relates to the consumption of fossil fuels, the remainder is existing biomass consumption of 825TJ.

Most Northland RETA emissions come from coal (Figure 2).

Figure 2 – 2020 annual emissions by process heat fuel in Northland RETA. Source: EECA

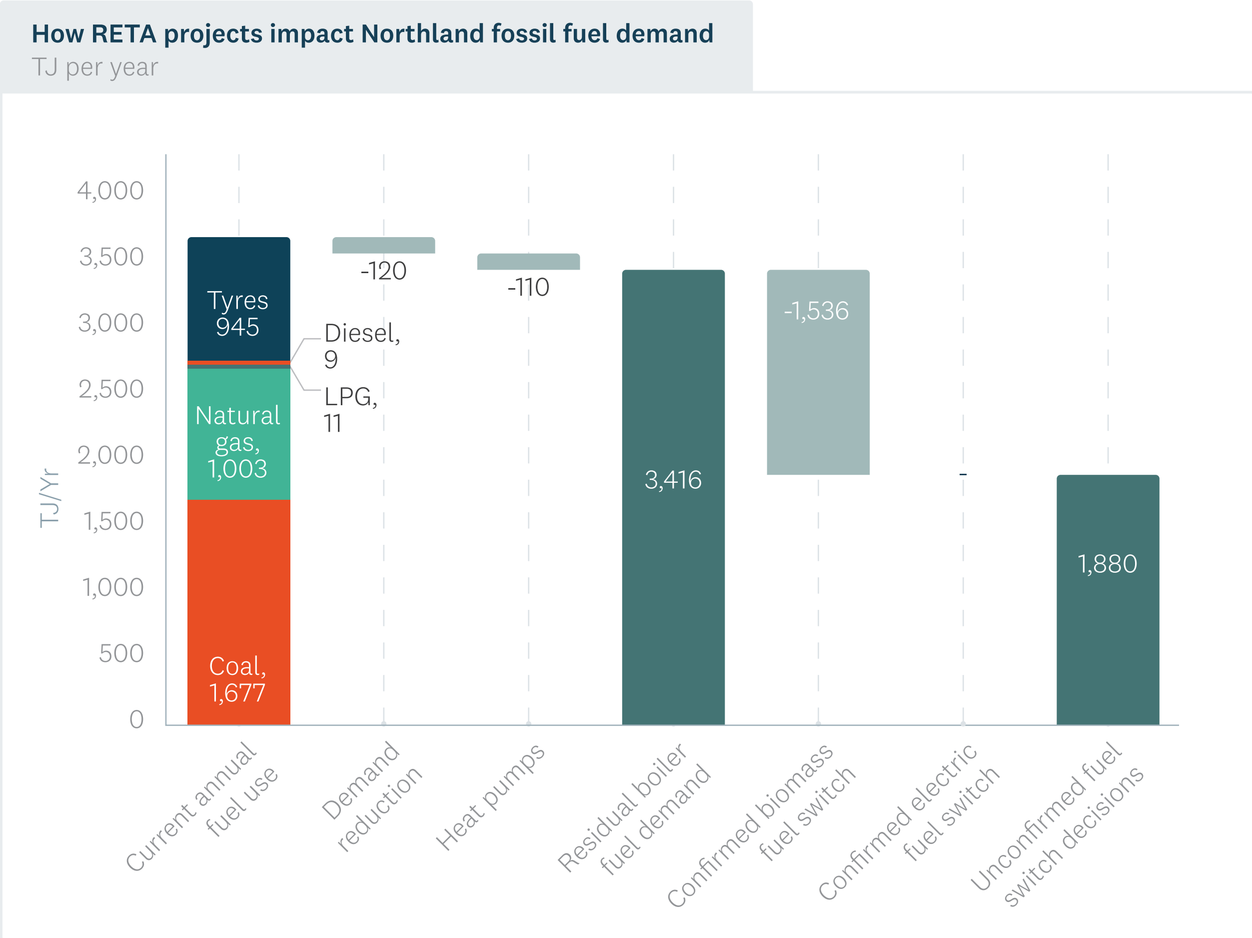


The objective of the Northland RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- Demand reduction (for example, reducing heat demand through process optimisation).
- Thermal efficiency (for example, installation of highly efficient heat pumps for hot water demands, possibly using heat recovery from refrigeration).
- Switching away from fossil-based fuels to a low-emissions source such as biomass and/or electricity.

Figure 3 below illustrates the potential impact of RETA sites on regional fossil fuel demand (excluding current use of biomass), both as a result of decisions where investment is already confirmed, and decisions yet to be made.

Figure 3 – Potential impact of fuel switching on Northland fossil fuel usage, 2022-2037. Source: EECA



This report looks at the impact of 31 emissions reduction projects across the 18 sites – covering demand reduction, heat pump efficiency, and fuel switching projects, and 3,646TJ of fossil fuel consumption. Further, it investigates the regional availability of biomass and electricity to replace natural gas, LPG, coal and diesel. Combining these two analyses – demand-side and supply-side – we can provide the indicative economics of each of the 31 process heat decarbonisation decisions.

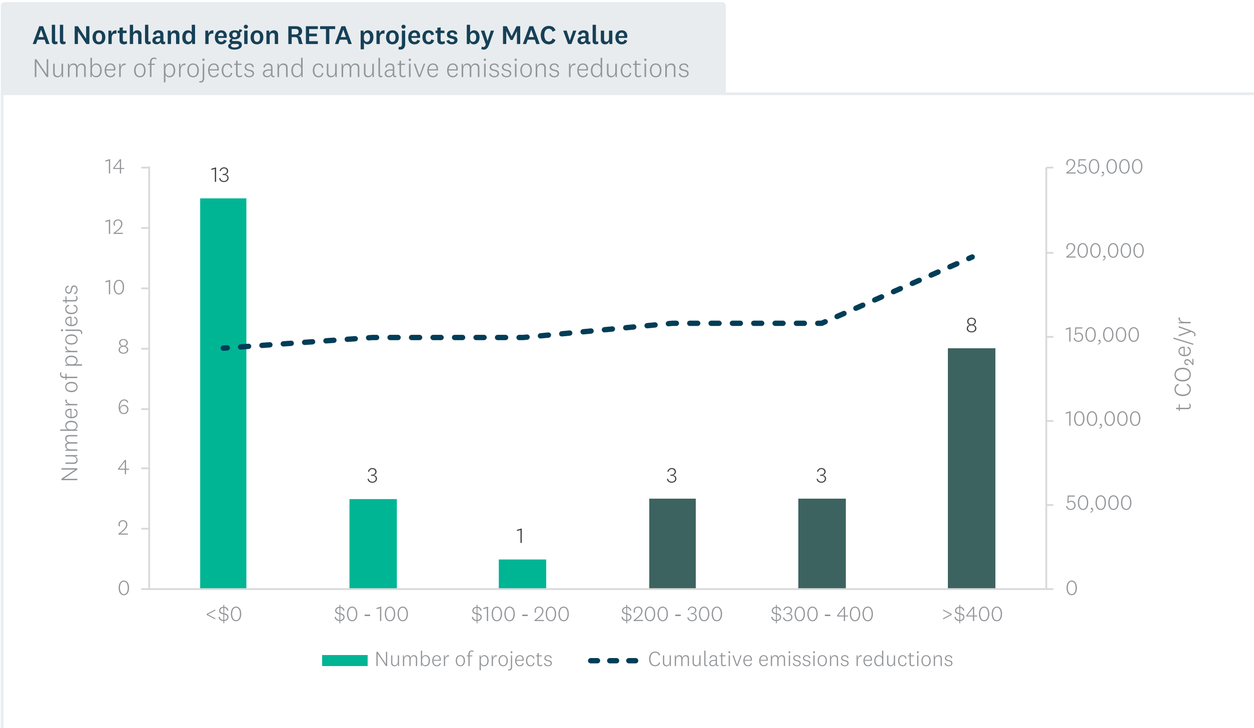
There are a range of decision criteria that individual organisations may use to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment, and other factors. It is challenging to incorporate many of these into a single analysis of the 'economics' of a decision.

Rather than attempt to include all these factors, we use a global standard 'marginal abatement cost', or 'MAC', to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment.

4.1 At expected carbon prices, 57% of emissions reductions from RETA projects are economic by 2050[3]

Figure 4 summarises the MACs associated with each decision, and the emissions reduced by these projects, based on the cost estimates outlined in this report.

Figure 4 – Number of projects by range of MAC value. Source: EECA



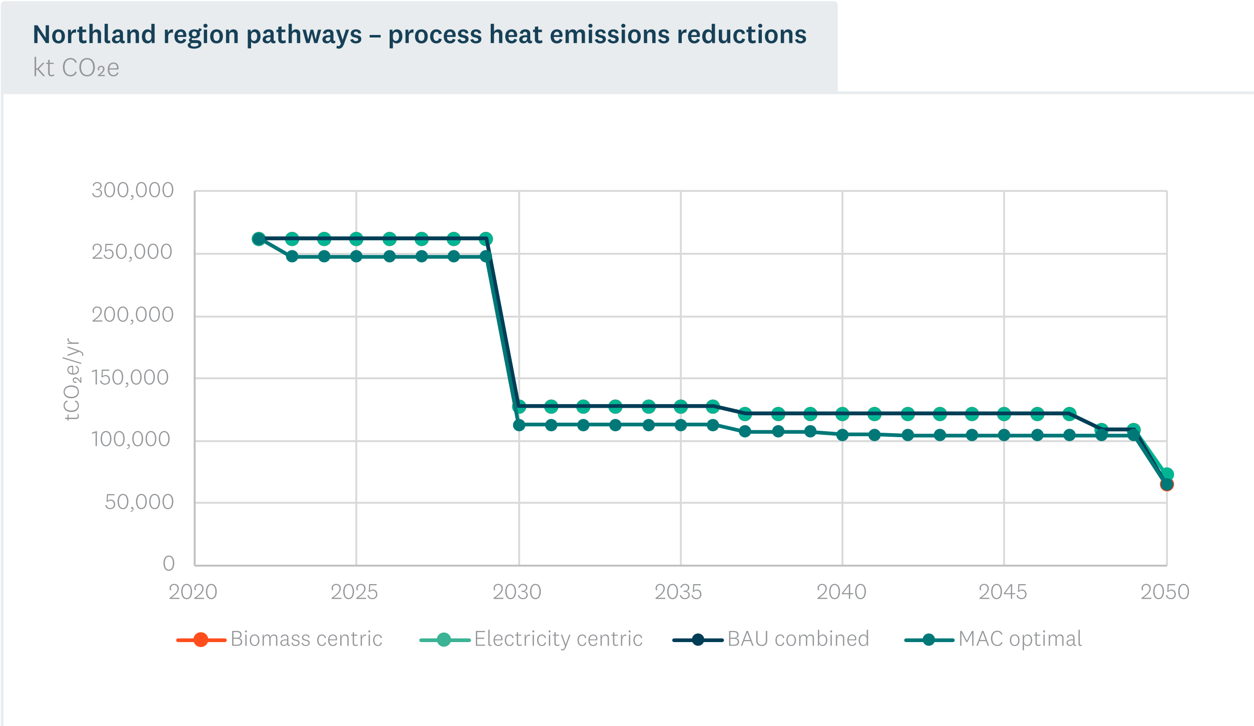
Out of 262kt of process heat emissions from Northland RETA sites, 149kt (57%) have marginal abatement costs (MACs) less than $200/tCO$_2$e.

Based on an expectation the carbon prices will follow the Climate Change Commission's Demonstration Pathway, these emissions reduction projects would be economic prior to 2037, when the use of coal boilers for process heat is expected to end.

Compared to a scenario where each of these projects was executed based on the organisations' current plans (a 'BAU' pathway), executing these projects using a commercial MAC decision-making criteria ('MAC Optimal') would accelerate decarbonisation, and reduce the cumulative release of long-lived emissions by 392kt over the period of the RETA analysis to 2050 (Figure 5).

[3] By 'economic', we mean that at a 6% discount rate these projects would reduce costs for the firms involved over a 20-year period (i.e. the Net Present Value would be greater than zero) using the cost estimates developed in this report, including at the assumed trajectory of carbon prices.

Figure 5 – Simulated emissions using Electricity Centric, Biomass Centric, BAU Combined and MAC Optimal pathways. Source: EECA



The significant reduction in emissions in 2030 results from the one planned fuel switching project (by Golden Bay Cement). For the remaining 17 unconfirmed fuel switching projects, the MAC optimal and BAU Combined pathways choose the fuel with the lowest MAC value. MAC values for each potential fuel – and the optimal fuel, and timing of investment – is driven by both the capital costs, and ongoing operational costs, of the investments. Operating costs are more important for electrification, while biomass MAC values in the Northland region are (generally) more driven by total capital costs[4].

A focus for companies considering electrification should be to find ways to reduce the total retail and network charges paid for electricity. The ability to enable flexibility in consumption – even just the ability to shift their demand forward or back by a small number of hours – could have a material effect on the overall economics of the project.

We tested a range of sensitivities on this modelling – higher and lower electricity prices, different decision-making metrics, and higher network upgrade costs for electrification options. While the pathway of emissions reduction was relatively unaffected, these sensitivities did change the modelled decisions for some process heat users.

The sensitivity analysis reinforced that process heat users should refine their understanding of their requirements, supply, logistics, and costs for both electricity and biomass before committing either way. This includes early and regular engagement with supply organisations (foresters and electricity companies).

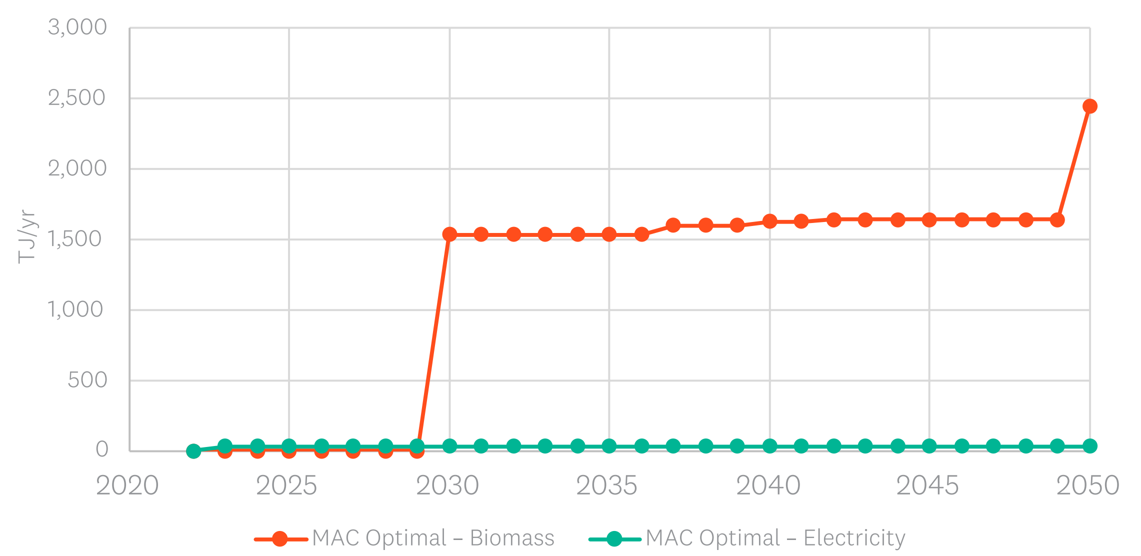
[4] This statement is specific to Northland and not a general statement about the difference between electricity and biomass. See discussion in Section 7.1.6.

4.2 What emissions reductions mean for fuel switching

From a supply-side perspective, the MAC Optimal pathway results in 1% of the process heat energy being supplied by electricity, and 99% by biomass (Figure 6).

Figure 6 – Electricity and biomass demand in MAC Optimal pathway. Source: EECA

Northland MAC Optimal pathways – electricty vs biomass demand
TJ per year



The sheer dominance of biomass reflects its lower overall cost as a fuel for large industrial and dairy projects which require high temperature boilers for their process heat[5].

Compared to sites analysed in the South Island, biomass in Northland is lower cost, due to the plentiful forestry resources. Further, the retail cost of electricity is higher than in the South Island, due to less favourable fuel-switching 'special pricing' deals being available from electricity retailers.

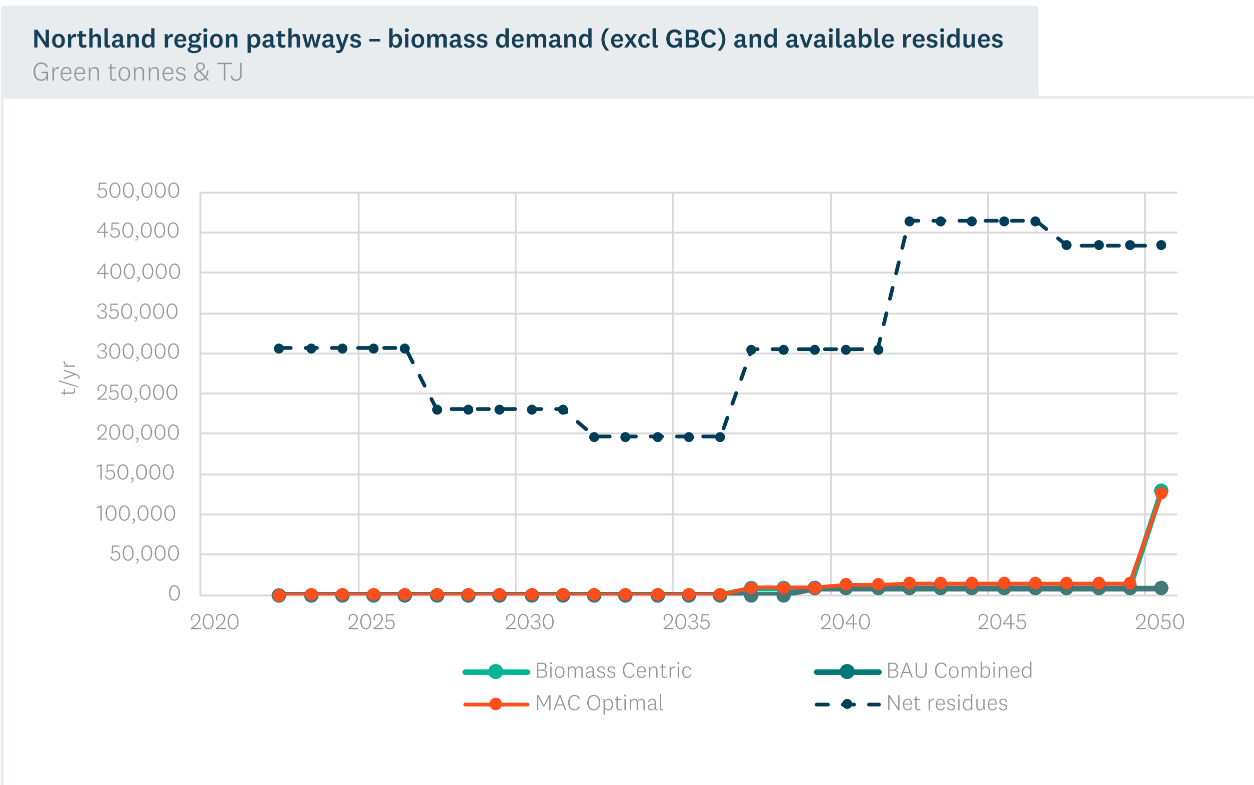
[5] That is, they can't fuel switch using high efficiency heat pumps alone.

While the fuel switching decision is typically the most significant in terms of energy usage and emissions reduction, it is important to recognise the impact that demand reduction and heat pump efficiency projects have on the overall picture of the Northland region's process heat decarbonisation. As shown in Figure 3 above, investment in demand reduction and heat pumps would meet 6% of today's Northland energy demands[6] from process heat, which in turn reduces the necessary fuel switching infrastructure required: thermal capacity required from new biomass and electric boilers would be reduced by 4MW if these projects were completed. We estimate that demand reduction and heat pumps would avoid investment of $4M to $6M in electricity and biomass infrastructure[7].

4.2.1 Biomass

Irrespective of the pathway, all biomass fuel switching projects, in aggregate, can be supplied by a combination of surplus processing residues and a pragmatic estimate of harvesting residues[8] (Figure 7). Note that Figure 7 has removed the significant biomass fuel requirements of Golden Bay Cement's planned 2030 decarbonisation investment projects (shown above in Figure 6), as we understand a large proportion of this biomass will be sourced from manufacturing, construction, and demolition waste streams.

Figure 7 – Growth in biomass demand under MAC Optimal and Biomass Centric[9] pathways. Source: EECA



6 This is true for both energy consumption and the peak thermal demand required from biomass or electric boilers.

7 On the assumption that the capital cost of electricity and biomass boilers, heat pumps and connection costs is between $1M and $1.5M per MW.

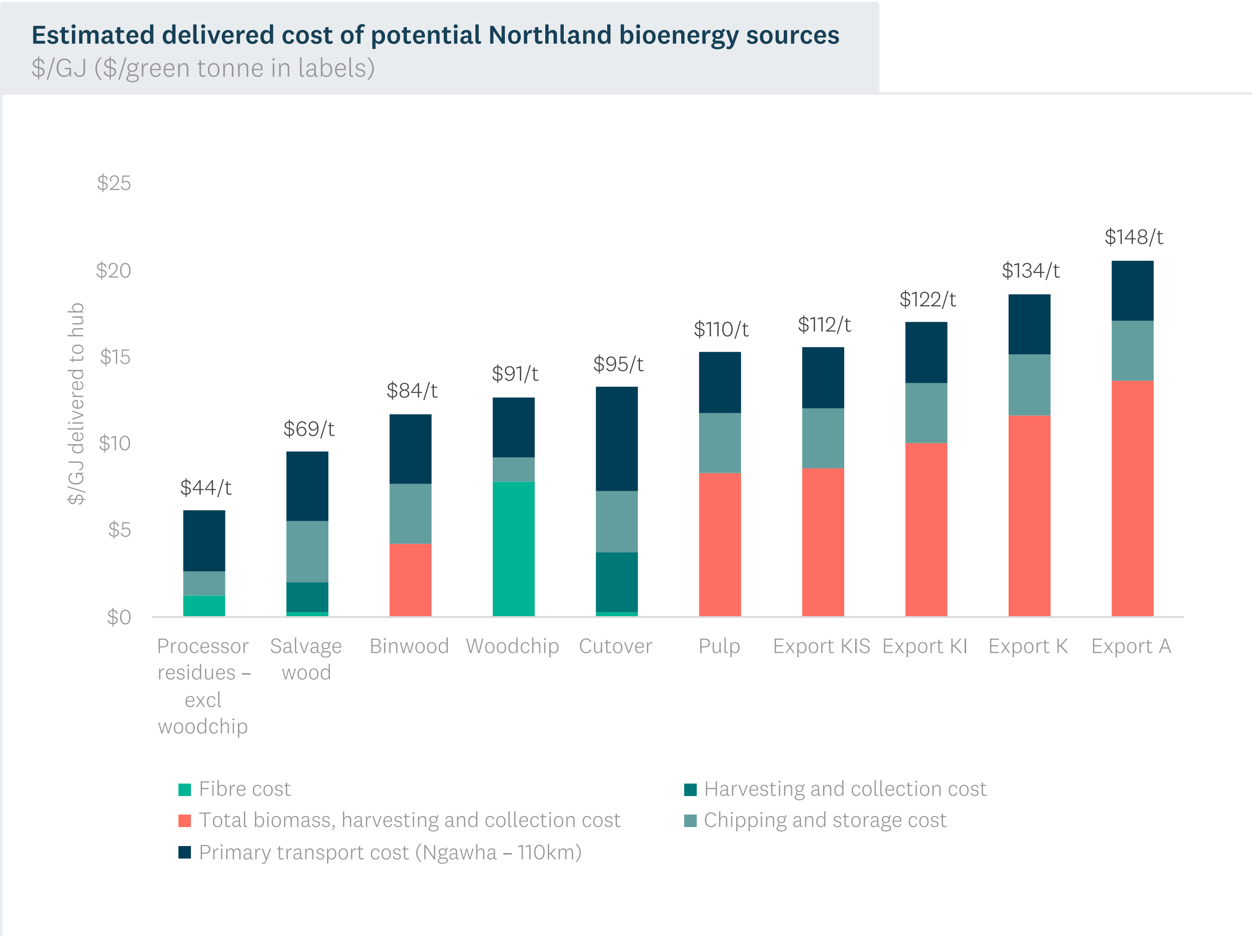
8 After deducting those being used for bioenergy today.

9 Biomass Centric is a version of the BAU pathway where all unconfirmed fuel switching projects choose biomass.

In the Northland region, harvesting and processing residues – even after netting off existing demand for these biomass sources – is more than sufficient to meet demand from process heat users. That said, neighbouring regions could also seek biomass from the forests that are included in the Northland RETA assessment, where transport costs and logistics make this practical. The potential for inter-regional trade in biomass will be considered when all North Island RETA reports are complete, and the whole island can be analysed.

Figure 8 shows costs of collection and delivered per volume of green tonnes and GJ.

Figure 8 – Estimated delivered cost of potential bioenergy sources. Source: Forme (2023)



Our assumption is that available biomass will be processed into pellets for smaller process heat users, and dried woodchip for large users. In our modelling, we assume that the available volumes in Figure 7 can be processed into woodchip and delivered to process heat users for $20/GJ ($260 per tonne of dried woodchip), while pellets will cost $24/GJ ($410/t).

Our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for these residues could be $73M (on a cost basis[10]).

10 Assuming an underlying cost of collecting these residues out of the forest of $10/GJ, as outlined in Section 8.

4.2.2 Electricity

Generation investment is expected to keep pace with the increase in national demand growth that arises from decarbonisation. This is likely to lead to modest increases in electricity prices for process heat consumers over the next 15 years. Forecasts obtained by EECA predict the wholesale and retail component of electricity charges increasing from around 11c/kWh in 2026 to 13c/kWh in 2037 (in real terms). We also note that some retailers are currently offering special prices for large process heat users who convert from fossil fuels to electricity. These special prices are slightly lower than the forecast numbers above.

In addition, the annual charges applied to major customers by EDBs for the use of the current distribution and transmission network can make up a significant component of the bill particularly where the annual electricity consumption is low relative to peak demand and/or connection size.

The Northland region is home to two electricity distribution businesses (EDBs) who maintain the myriad assets that connect consumers to Transpower's national grid. These EDBs also work with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand. These entities are facing increased demands from the region as consumers consider the electrification of transport and process heat.

The precise way in which Northland's EDBs calculate distribution charges (and pass through transmission charges) has been converted into an approximate per-MVA charge in the table below. Process heat users should engage with their EDB to obtain pricing tailored to their size and location.

Table 2 – Estimated and normalised network charges for large industrial process heat consumers by EDB; $ per MVA per year

EDB	Distribution charge	Transmission charge	Total line charge
Northpower	$90,700	$16,300	$107,000
Top Energy	$150,000	$50,000	$200,000

Finally, we estimate the network upgrades required to accommodate each of the 16 process heat users in the RETA study who are contemplating electricity as a fuel switching option.

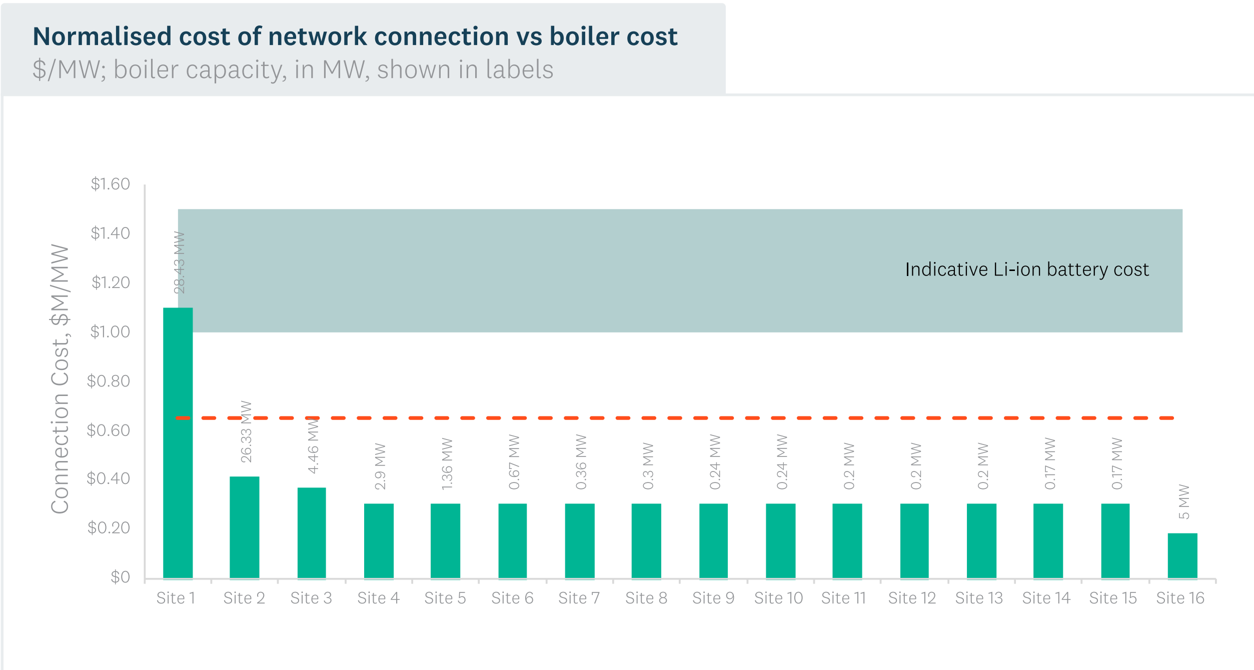
For most sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Most of these minor upgrades would have connection costs under $1.0M (and many under $300,000) and experience connection lead times of less than 12 months.

More substantial upgrades to the distribution network are required for two of the 16 sites, with commensurately higher costs (mostly between $1.2M and $8.0M) and longer lead times (12-30 months).

One site may require major distribution and transmission upgrades, depending on the number of boilers that are converted to electricity, and the level of network security required. The cost of the upgrades may reach $23M and take up to 36 months to execute.

These costs are summarised (in $/MW) in Figure 9. We note these costs represent the estimated total construction costs of the expected upgrades, with the caveats outlined in Section 9.3. We recommend process heat users engage with their EDB to discussion options for connection, more refined cost estimates, and the degree to which process heat users need to make capital contributions to these upgrades. Figure 9 also compares these per-MW connection costs with the cost (again, per MW) of a battery. We provide this comparison because the ability to shift demand forward or back in time (using batteries, hot water, ice slurry etc) could reduce the capacity required from new network investment. It could also reduce a site's network charges, where these are based on some measure of peak demand. However, we note that storage devices are not a perfect substitute for network capacity, as their ability to reduce demand is usually limited to a small number of hours at any point in time.

Figure 9 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



Based on the various electricity cost parameters, including a 50% contribution to the cost of network upgrades, only 1% of the energy required under the MAC Optimal pathway is supplied by electricity. Our sensitivity analysis suggests this outcome is relatively robust under different electricity price scenarios.

The critical aspect of electricity demand growth that concerns network owners is not the growth in electricity consumption resulting from new electric boilers and heat pumps (around 16% of current Northland electricity consumption if all process heat electrified), but rather the impact on the network's peak demand that arises from electrification of boilers.

Figure 10 – Potential increase in Northland peak electricity demand under MAC Optimal and Electricity Centric pathway. Source: EECA

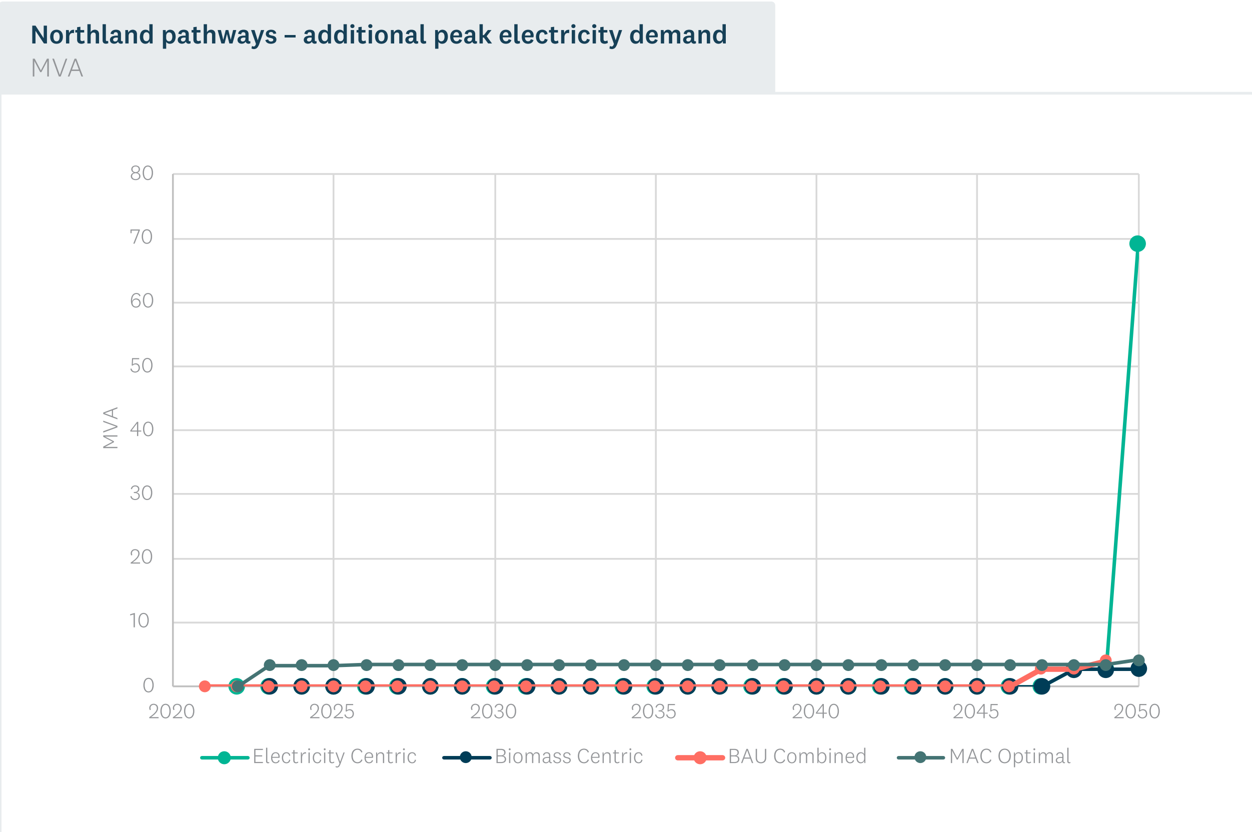


Figure 10 shows that should all unconfirmed process heat users in Northland convert to electricity (the 'Electricity Centric' pathway), the increase in demands on the two EDBs could be significant by 2050 – an increase in peak demand of 69MW[11], or 30% compared to today. However, if the decision making follows the commercial guidelines in our MAC Optimal pathway, the network requirements would be much lower, given the dominance of biomass in this pathway. Table 3 breaks this down by EDB.

11 This chart shows the cumulative increase in peak demand assuming all electrode boilers peak at the same time. The main report discusses a more realistic view which considers the natural diversity between process heat users in terms of when each is likely to peak. This results in a slightly lower peak demand requirement from the networks.

Table 3 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Northpower	66	$17.3	4.0	$0.1
Top Energy	3	$0.0	0.1	$0.0
Total	**69**	**$17.3**	**4.1**	**$0.1**

The costs presented in Table 3 are the total construction costs associated with any network upgrade costs, and may not necessarily reflect the connection costs paid by RETA organisations, as they may be shared between the EDB and the new process heat user. These costs also exclude the ongoing network charges paid by each process heat user that electrifies their process heat.

Northpower will experience the largest increase in process heat-related electricity demand in both pathways. The extent to which this increase in peak demand triggers investment in network capacity depends on a number of factors, such as existing spare capacity and security of supply requirements.

Both the cost faced by process heat users to connect their electric boilers to the network, and the wider network upgrades that Transpower and the EDBs are contemplating, could be reduced by harnessing the potential for process heat users to be flexible about when they use their boilers. We highlighted above how demand reduction and heat pumps have reduced the need for thermal capacity by around 4MW. Similarly, if process heat users could shift some or all their electricity consumption away from critical peak times on the network (usually winter mornings and evenings), or maintain an alternative supply of fuel, a greater degree of cost savings could be experienced. While the ability to shift demand relies on having some degree of flexibility or storage in the process, studies have estimated sites could save between 8% and 18% of their electricity procurement costs, and between $150,000 and $300,000 per MW[12] of electricity infrastructure costs every year.

12 See https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-under-100-renewable-electricity-supply/, specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

4.3 Recommendations and opportunities

Our analysis has highlighted a range of opportunities and recommendations which would improve the overall process heat decarbonisation 'system'. These recommendations are summarised here.

Recommendations to improve the use of biomass for process heat decarbonisation:

- **More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the 'integrated model' of cost recovery, outlined above, achieve the best outcomes in terms of recovery cost and volumes.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **Mechanisms should be investigated and established to help suppliers and consumers to see biomass prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.**
- **National guidance or standards should be developed, based on international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**

Recommendations to improve the use of electricity for process heat decarbonisation:

- **EDBs should proactively engage on process heat initiatives to understand their intentions and help process heat users obtain a greater understanding of required network upgrades, cost, security levels, possibilities for acceleration, use of system charges and network loss factors. EDBs should ensure Transpower and other stakeholders (as necessary) – at an early stage – are aware of information relevant to their planning.**
- **Process heat users should proactively engage with EDBs, keeping them up-to-date of their plans with respect to decarbonisation, and providing them with the best information available on the nature of their electricity demand over time (baseload and varying components); the flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice in response to system or market conditions; the level of security they need as part of their manufacturing process, including their tolerance for interruption; and any spare capacity the process heat user has onsite. While the costs associated with network connection used in this**

report have been estimated based on the best publicly available information available to us, when process heat users provide the information above, it will allow EDBs to provide more tailored options and cost estimates.

- **EDBs should develop and publish clear processes for how they will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**

- **EDBs and process heat users should engage early to allow the EDB to develop options for how the process heat user's new demand can be accommodated, what the capital contributions and associated network charges are for the process heat user, and any role for flexibility in the process heat user's demand.**

- **To support this early engagement, EDBs should explore, in consultation with process heat users and EECA, the development of a 'connection feasibility information template' as an early step in the connection process. This template would include a section for process heat users to provide key information to EDBs, and a network section where EDBs provide high-level options for the connection of the process heat user's new demand. Information provided by EDBs would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer's flexibility.**

- **Retailers, flexibility aggregators, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**

- **The electricity sector and process heat users should collaborate to explore and demonstrate flexibility. This is consistent with steps in the FlexForum's Flexibility Plan.**

- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.**

- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**

Recommendations to assist process heat users with their decarbonisation decisions:

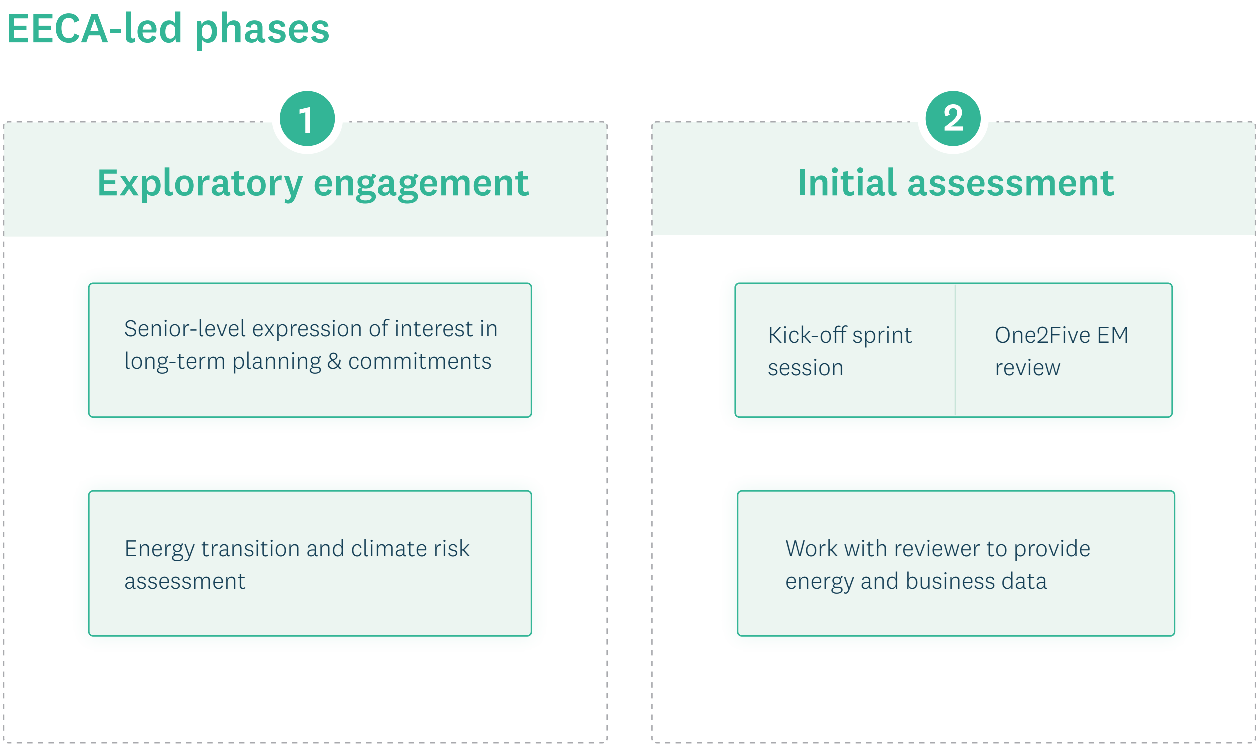
- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**

5 Introduction

5.1. The Energy Transition Accelerator programme

EECA has run the ‘Energy Transition Accelerator’ (ETA) programme since 2019. The programme aims to support New Zealand’s largest businesses to make technically and economically viable process heat decarbonisation decisions and investments which support their energy transition pathway to a low-carbon future. EECA assists organisations in committing to a longer-term transition, based on the opportunities and risks on the economic and technological horizons. The ETA programme is designed to help businesses prepare for the future, by capitalising on the process heat energy and carbon saving opportunities that are in the pipeline now, and beyond 2030. An overview of the ETA programme is shown in Figure 11 below, while the key components of a process heat decarbonisation analysis for an individual organisation are described in Appendix A.

Figure 11 – Overview of the Energy Transition Accelerator programme. Source: EECA



All existing EECA business tools remain available as appropriate (e.g. One2Five, business cases, feasibility studies, technology demonstrations).

Customer-led phases

3

Detailed analysis and pathway setting

- GHG accounting
- Extensive energy audit
- Feasibility studies
- Pinch analyses
- Energy management system enhancement
- ETA steering group established internally

4

Planning, implementation and review

- Develop and implement energy transition pathway plan
- Track/review/improve

Celebrate success

The philosophy underpinning the ETA programme aligns with EECA's strategic principles:

- Focus on impact (target largest emitters).
- Understand the organisation (direct engagement and long-term support).
- Define the problem (root cause analysis).
- Join the dots (work with and connect people and organisation).
- Display leadership (pro-active action, fact-based approach).

The number of companies that EECA assists in ETAs provides the ability to use some of the individual information collected to develop an analysis of regional process heat decarbonisation pathways. This analysis informs coordination and information challenges faced by individual organisations when dealing with process heat problems that were collective in nature, such as the need for common infrastructure or new markets.

EECA's Regional Energy Transition Accelerators (RETAs) are the projects that provide this regional perspective.

5.2 Northland region Energy Transition Accelerator projects

There are two stages of a RETA project – planning, and implementation. This report is the culmination of the RETA planning stage in the Northland region.

The first planning phase aims to:

- Provide coordinated information specific to the region so that process heat users can make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities, and recommendations.

The implementation stage aims, through collaboration with regional stakeholders, to:

- Identify and address the regional barriers or opportunities in process heat decarbonisation which could benefit from government support.
- Identify and commit to opportunities to fast-track process heat decarbonisation projects.

EECA acknowledges that the RETA focus does not consider in any detail the interaction with transport, which is also drawing on electricity (electric vehicles and hydrogen) and bioenergy (biofuels) to decarbonise. A proper whole-of-system approach would span all forms of energy demand and consider the interconnections, but this was not possible in the time available for this first, ground-breaking project. This report acknowledges obvious links to other sectors where applicable.

Further, this RETA report is based on what is known at the time of writing. We acknowledge that the nature of energy supply and demand is changing faster than at any time in history, both domestically and globally. Future iterations of RETA analyses could consider current and likely future demands from other sectors, future changes in the energy system, including new technologies, markets, and sources of energy.

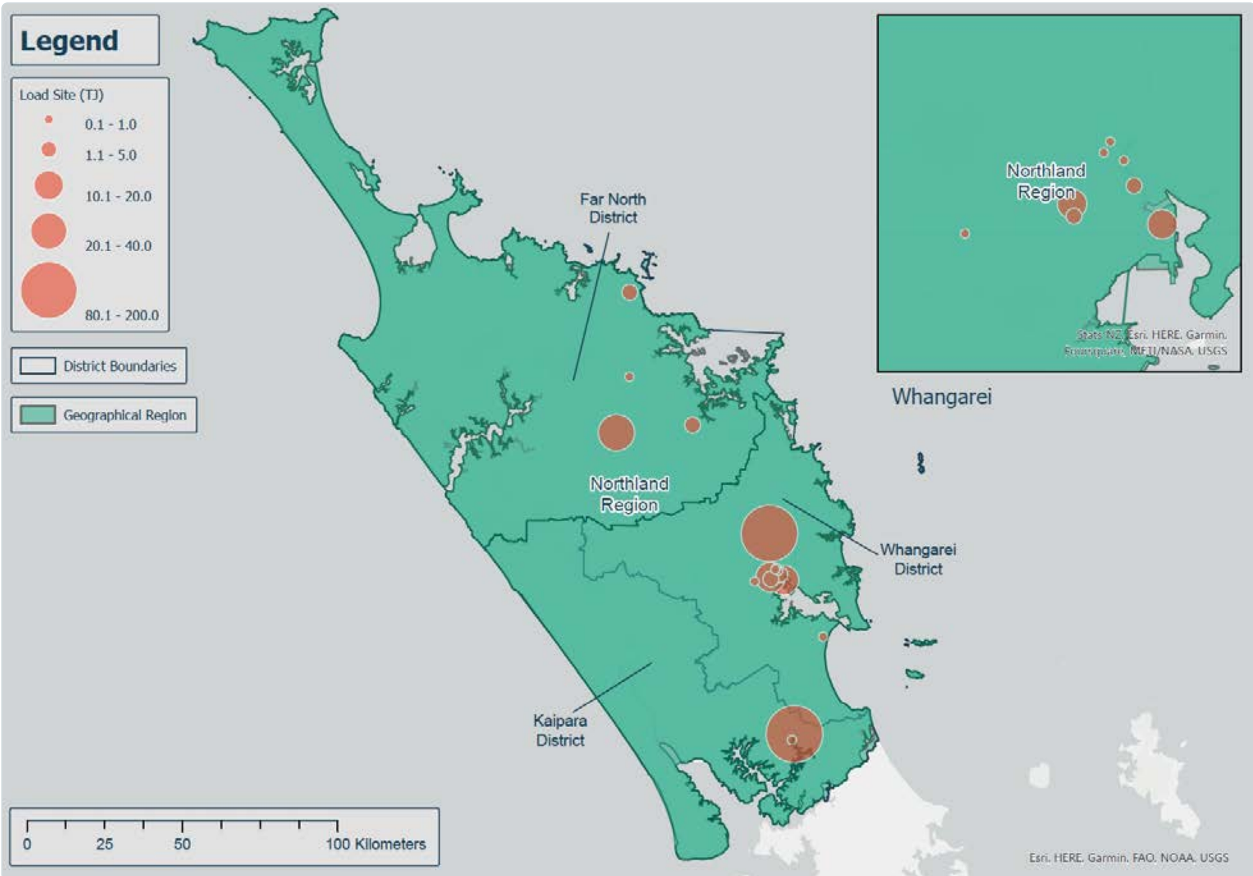
Maungaraho Rock Scenic Reserve, Northland, New Zealand. Credit – Northland NZ.

6 Northland process heat – the opportunity

6.1 The Northland region

Figure 12 illustrates the region considered in this report, with the process heat sites located and sized according to their annual energy requirements.

Figure 12 – The Northland RETA region



6.2 Northland regional emissions today

StatsNZ's regional greenhouse gas inventory presents emissions for the whole Northland region. Like much of New Zealand, greenhouse gas emissions in the Northland region (expressed in carbon dioxide equivalent, or 'CO_2e') are dominated by agricultural emissions, making up 1,707kt (47%) of emissions out of the region's total emissions of 3,601kt (Figure 13). Energy is the second largest emitting sector, with 1,310kt (36%), split between transport and stationary energy.

Figure 13 – Emissions inventory for the Northland region. Source: StatsNZ[13]

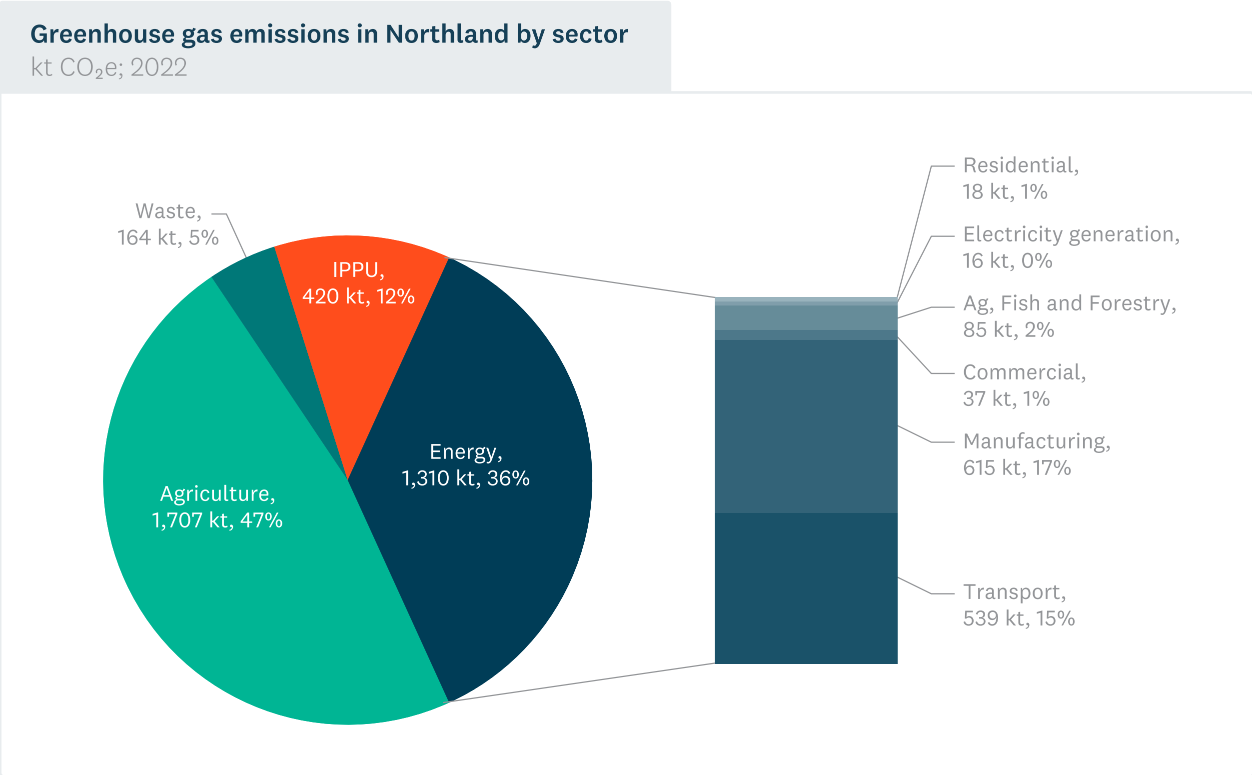


Figure 13 breaks energy emissions down into sector sources. Electricity generation and residential emissions are outside the focus of the RETA study. We expect that most agriculture emissions relate to off-road vehicle use or diesel generators. We conclude that the majority of the remaining 652kt of commercial and manufacturing emissions would be 'process heat'.

[13] In this chart, 'Agriculture' stationary energy covers all agriculture sectors, and includes forestry and fishing. 'IPPU' is Industrial Process and Product Use, which includes some of the non-energy related emissions from Golden Bay Cement.

6.2.1 Emissions coverage of the Northland region RETA

The Northland RETA covers a total of 18 process heat sites spanning dairy, industrial (including cement production and wood processing) and commercial (predominantly facility heating). To target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled process heat equipment above 500kW and any other sites (e.g. schools) where EECA had information from various programmes (e.g. EECA's Regional Heat Demand Database (RHDD)[14] and ETA) up to 2022. These sites are summarised in Table 4.

Most of the sites are commercial in nature, but most emissions arise from the industrial sector.

Table 4 – Summary of fuel consumption and emissions from process heat sites included in Northland RETA. Source: EECASource: EECA

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Dairy	2	93	264	950	51
Industrial	6	148	960	3,456	208
Commercial	10	16	18	66	4
Total	**18**	**257**	**1,242**	**4,472**	**262**[15]

Overall, the Northland region RETA sites in aggregate account for 262kt of process heat greenhouse gas emissions, around 40% of the 652kt of commercial and manufacturing energy emissions shown in Figure 13. We expect that the difference between StatsNZ's inventory estimate and the emissions covered by the Northland RETA can be explained primarily by three reasons:

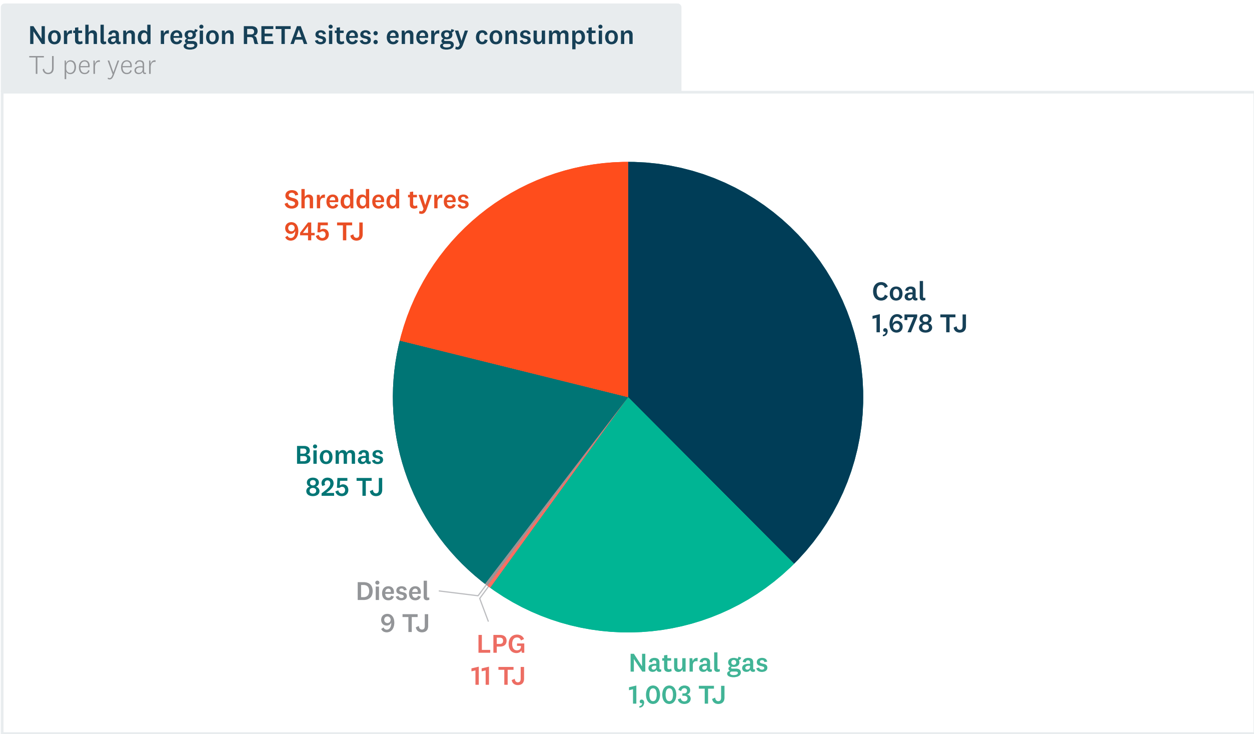
- RETA focuses primarily on boilers larger than 500kW. We expect that a large proportion of the remaining 77kt of stationary emissions, not accounted for in the RETA sites, relate to boilers below 500kW.
- There will be a component of commercial emissions that is a result of the use of LPG for cooking in commercial kitchens and restaurants, as well as for space and water heating in commercial buildings. We expect that this is particularly the case for regions such as Northland which have a major urban centre (Whangarei).
- StatsNZ regional emissions estimates are based on national assumptions around the average emissions intensity (per dollar of GDP) of different subsectors of the economy. Although these intensities are accurate at the national level, in any given location around the country, the emissions intensity of any individual economic activity can deviate markedly from national averages.

We now consider the source of RETA emissions by fuel. Current process heat requirements met by direct use of 4,472TJ natural gas, LPG, diesel, shredded tyres and biomass (Figure 14). Of this, 3,646TJ of consumptions relate to fossil fuels, with an additional 845TJ of fuel coming from biomass.

14 See https://www.eeca.govt.nz/insights/eeca-insights/regional-heat-demand-database

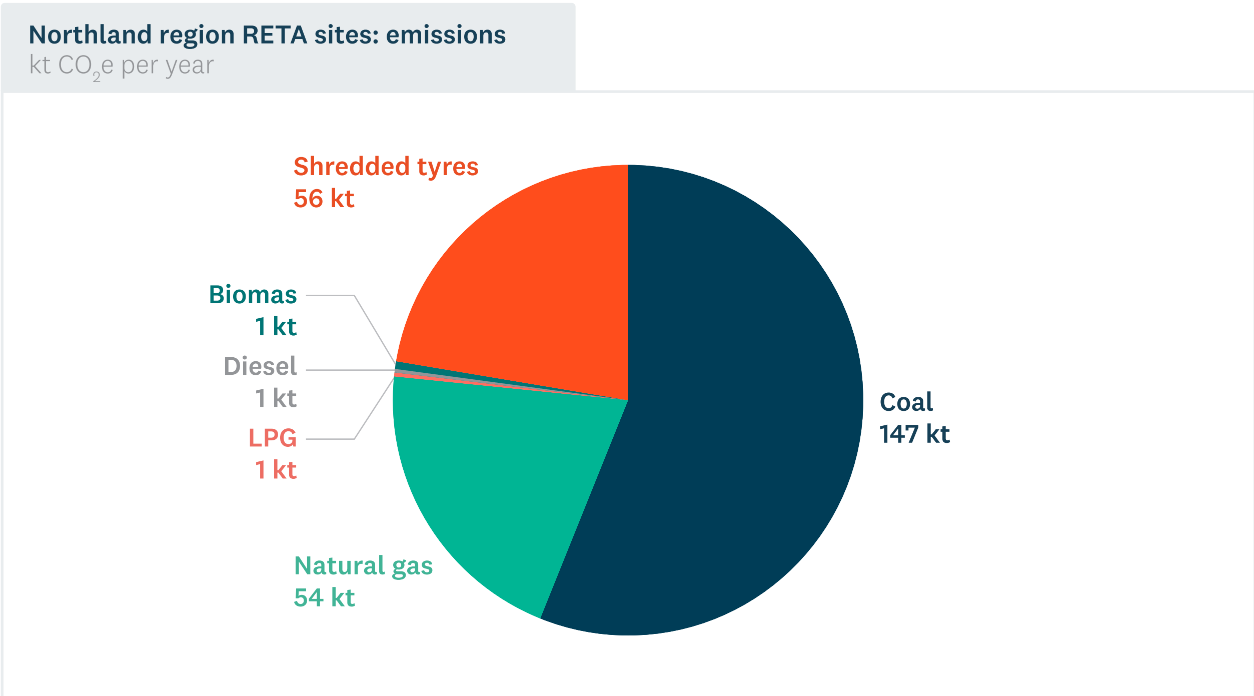
15 The difference between the total and sum of each sector is due to rounding.

Figure 14 – 2020 annual process heat fuel consumption in Northland RETA. Source: EECA[16]



Most Northland RETA emissions[17] come from coal (56%), shredded tyres (22%)[18], and natural gas (21%). Emissions from LPG are insignificant (0.7% of total process heat emissions). (Figure 15).

Figure 15 – 2020 annual emissions by process heat fuel in Northland RETA. Source: EECA



[16] Shredded tyres are used by Golden Bay Cement.

[17] Emissions factors used for fossil fuels are as follows (t CO_2e per t of fuel): Lignite: 1.43; Sub-bituminous coal: 2.01; Diesel: 2.26; LPG: 3.03.

[18] These are used by Golden Bay Cement.

6.3 Characteristics of RETA sites covered in this study

As outlined above, there are 18 sites considered in this study. Across these sites, there are 31 individual projects spanning the three categories discussed in Section 6.3 – demand reduction, heat pumps and fuel switching. Table 5 shows the different stages of completion of the RETA process heat projects. As can be seen, only one project has been confirmed, which involves fuel switching. Of the unconfirmed projects – i.e. those that are yet to commit to the final investment – most are investigating the fuel switching option.

Table 5 – Number of projects in the Northland region RETA by category. Source: Lumen, EECA.

Status	Demand reduction	Heat recovery	Fuel switching	Total
Confirmed	0	0	1	1
Unconfirmed	7	3	20	30
Total	**7**	**3**	**21**	**31**

6.4 Implications for local energy resources

All RETA decarbonisation pathways (presented in Section 7) expect that the 18 Northland region RETA sites, representing 3,646TJ pa of fossil fuelled energy consumption for process heat in 2022, will have executed demand reduction projects and switched to low emissions fuel[19] before 2050. The rate at which the unconfirmed fuel choices are made are the subject of the rest of this report. Whichever way this occurs, the outcome has potentially significant implications for the use of various fuels and resources in the region.

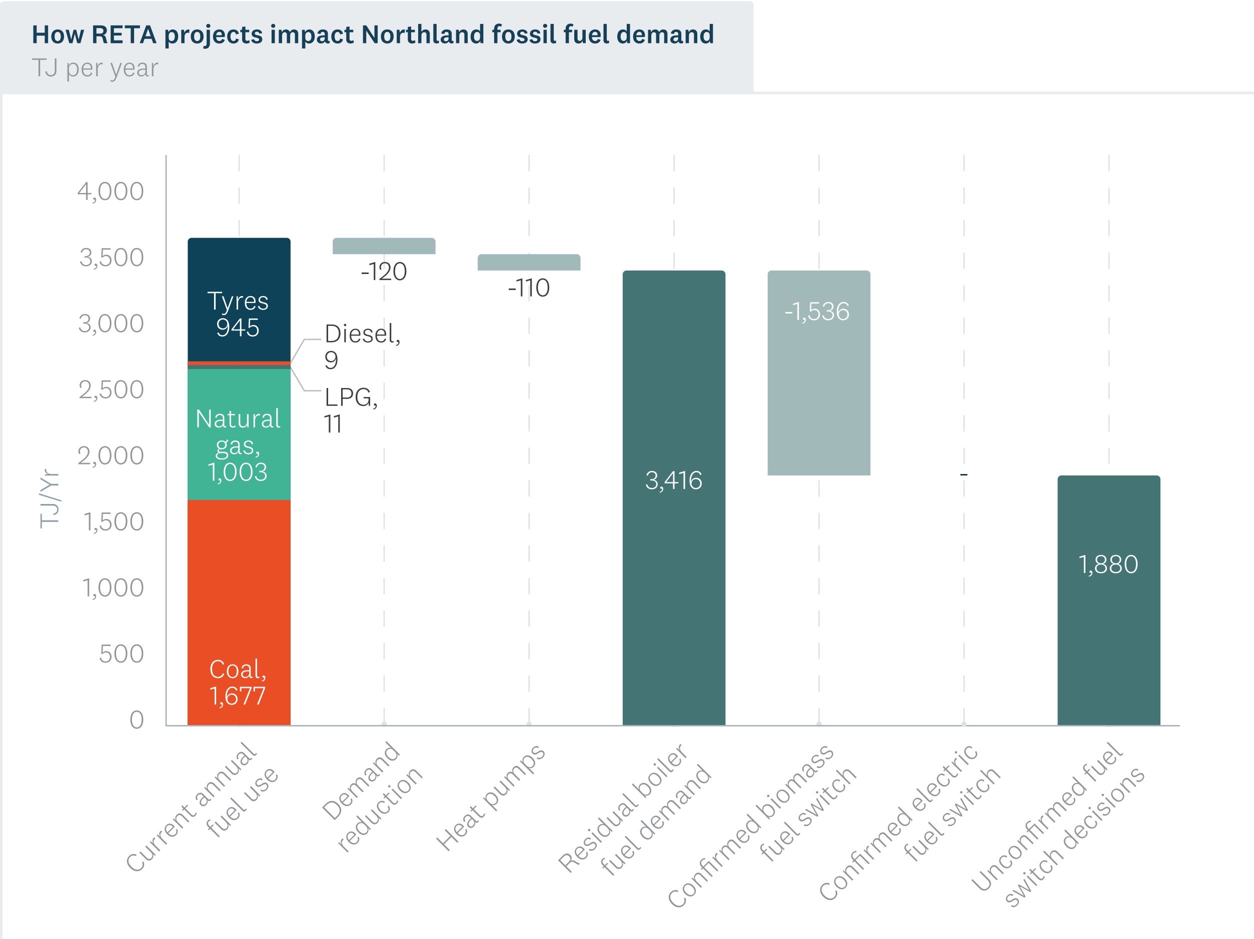
As outlined above, demand reduction and heat pumps (for heat recovery and efficiency) are key parts of the RETA process and, in most cases enable (and help optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, though, due to the higher capital and fuel intensity of this decision. However, in assessing the required boiler capacity for each unconfirmed fuel switching project, this report assumes that every site has invested in a demand reduction project. Where applicable[20] it will also assume a heat pump will be installed – even for only part of the site heat needs – as this could see significant efficiencies achieved. These investments will reduce fossil fuel consumption, and the low-emissions fuel required for the remaining process heat needs.

These components are presented in Figure 16, to provide a picture of how fossil fuel use may change over the period of the RETA study.

19 Including any use of heat pumps to achieve increased efficiency.

20 That is, where there is a low temperature heat requirement. It will not assume a heat pump for sites that have confirmed a switch to biomass for low-temperature heat needs.

Figure 16 – Potential impact of fuel switching on Northland region fossil fuel usage, 2022-2050. Source: EECA



Ngāwhā Springs, Northland, New Zealand. Credit – Top Energy.

As 3,416TJ of fuel switching decisions are unconfirmed, the magnitude of change in biomass and electricity demand cannot be known with any precision. However, we can say:

- If all unconfirmed fuel switching decisions choose electricity, this could result in an increase in instantaneous electricity demand of 69MW across the two electricity distribution networks[21] by 2050, if all sites reached their maximum outputs at the same time[22]. This instantaneous demand would increase the maximum demand in the region by 30%[23]. These electrification decisions would also increase the annual consumption of electricity by 245GWh, approximately 16% of today's gross electricity consumption[24] in the Northland region.
- If all unconfirmed boiler fuel switching decisions choose biomass, this – combined with confirmed biomass projects – could result in an increase of 340,422t by 2050 (see Section 8.7). Assuming sufficient resources were available, this is a five-fold increase in the use of biomass for heat compared to our estimate that, today (in 2022), around 65,490t of biomass is used for heat.[25]

These two scenarios paint the 'end points' of a spectrum of mixes of biomass and electricity fuel switching decisions. The reality is that each process heat user will make fuel switching decisions based on their own requirements and drivers.

The degree to which the resulting fuel demand – in a range of scenarios – can be met through local resources (electrical or biomass-related) is considered in Section 7.

In Table 6 below we show the expected remaining fuel demands from each site in the Northland RETA, after any demand reduction projects and/or heat pump projects are accounted for. We present biomass demands both in TJs and wet tonnes (55% moisture content) and report the peak demand from the boiler should it convert to electricity.

As mentioned, only one site (Golden Bay Cement) has fuel switching planned (shaded in green), representing a demand for 1,537 TJ (213,800t) of biomass. The potential fuel switching decisions associated with the 20 unconfirmed sites will be the focus of Section 7.2. We highlight in orange the preferred fuel based on the MAC Optimal calculations outlined in Section 7.1.2.

We note that Golden Bay Cement is aiming to replace all of their coal use by 2030. Any additional biomass required to supplement other alternative fuels (such as shredded tyres) for this transition will be primarily construction and demolition waste sourced from Northland and Auckland, and a feasibility study of this option is currently underway (Golden Bay Cement are also looking at reducing the clinker content in their final product by using Supplementary Cementitious Materials (SCM)). Because this additional biomass resource is not from the Northland forest harvests, Golden Bay Cement's biomass is not included in this report's assessment of regional biomass demand. However, the resulting emissions reduction will be included in the Northland pathways developed in Section 7.2.

21 Northpower and Top Energy.

22 It is unlikely that all sites reach their peak demands at the same time. See Section 9.4 for an analysis.

23 According to EDB disclosure information, maximum demand in 2022 for each network is: Northpower: 157MW; Top Energy: 78MW. Under the Electricity Centric scenario, Northpower would experience the highest relative increase in maximum demand. Transpower reports that the 2022 regional peak demand was 226MW, indicating that there is a small amount of diversity between the individual EDB peak demands and the overall regional peak demand.

24 Northland regional electricity consumption is around 1,270GWh per year (source: emi.ea.govt.nz).

25 As outlined below, 50,000t of this biomass is procured from outside Northland, and is currently used at Golden Bay Cement.

Table 6 – Summary of Northland region RETA sites with fuel switching requirements. Green shading indicates confirmed projects; orange highlighting indicates the preferred fuel option according to a commercial decision making criteria explained below.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Golden Bay Cement, Whangarei	**Industrial**	**Confirmed**	**1,535.6 (213.8)**	
Fonterra, Kauri	Dairy	Unconfirmed	**412.1 (32.7)**	1-25
Fonterra, Maungaturoto	Dairy	Unconfirmed	**370.8 (29.4)**	8-28
Juken Nissho, Kaitaia LVL	Industrial	Unconfirmed	**63.4 (5)**	
Northland Regional Corrections Facility	Commercial	Unconfirmed	**11.5 (0.7)**	2.9
Imerys Ceramics New Zealand Limited, Matauri Bay	Industrial	Unconfirmed	**27.5 (1.6)**	1.4
Northland DHB, Whangarei Hospital	Commercial	Unconfirmed	**16.3 (1.3)**	2.9[26]
Northland Polytechnic	Commercial	Unconfirmed	13.6 (0.8)	**0.36**
Whangarei District Council, Aquatic Centre	Commercial	Unconfirmed	9 (0.5)	**0.24**
Downers Whangerai Asphalt Plant	Industrial	Unconfirmed	**3.8 (0.3)**	5
Whangarei Council, Maunu Cemetery	Industrial	Unconfirmed	**1.5 (0.1)**	0.2
Kerikeri Crematorium, Kerikeri	Industrial	Unconfirmed	**1.5 (0.1)**	0.2
Ministry of Education, Whangarei Girls High School	Commercial	Unconfirmed[27]	1.2 (0.1)	**0.24**
Ministry of Education, Otamatea Highschool	Commercial	Unconfirmed	**0.8 (0.05)**	0.17
Ministry of Education, Whangarei Boys High School	Commercial	Unconfirmed[28]	1 (0.1)	**0.2**
Ministry of Education, Bream Bay College	Commercial	Unconfirmed	0.8 (0.05)	**0.17**
Ministry of Education, Bay of Islands College	Commercial	Unconfirmed	0.5 (0.03)	**0.3**

26 This is for decarbonisation projects only; the increase in total demand may be much higher due to the hospital rebuild and expansion.

27 We understand these projects are now confirmed, but this was not the case at the time the analysis was complete.

28 We understand these projects are now confirmed, but this was not the case at the time the analysis was complete.

7 Northland's decarbonisation pathways

As outlined above, a primary driver for the RETA approach is to identify where the collective decisions of process heat users, and potential providers of low-emissions process heat fuel (biomass or electricity), give rise to 'system' challenges and opportunities. These challenges and opportunities may not be apparent to individual RETA projects, as they only become apparent when the collective impacts of many RETA project decisions are considered. If these challenges and opportunities can be anticipated, and the types of conditions under which they might occur, they can be addressed in advance, improving process heat users' ability to make informed decarbonisation decisions.

The modelling presented below uses the detailed information from Sections 8 and 9 to develop different scenarios of the pace and magnitude of electricity and biomass uptake across the whole Northland region. We refer to each of these scenarios as 'decarbonisation pathways'.

7.1 Simulating process heat users' decarbonisation decisions

To explore different decarbonisation pathways for Northland, we must develop a simple, repeatable methodology to simulate the decisions of process heat users – specifically, which low-emissions fuel (electricity or biomass) will they choose to replace their existing fossil fuel, and when would they make that investment.

As explained in Section 7.2 below, some of our pathways are highly simplistic in this respect – representing all (unconfirmed) process heat users choosing biomass, or all choosing electricity. These pathways are somewhat unrealistic in most regions but serve a useful purpose of 'bookending' future demand for each type of fuel. In order to increase our understanding of more realistic scenarios, we also explore pathways which simulate a world where process heat users choose their investment using a more commercial decision-making process.

There are a range of factors organisations face when deciding when to invest in decarbonisation, and which fuel to choose. These factors will invariably include the financial cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing or consumer expectations.

However, the softer factors are harder to model quantitatively. As a result, the methodology used here focuses on the financial components of the investment decision that can be modelled with available data. These are primarily factors relating to efficiencies and costs listed above, as well as known information about the current annual consumption of heat at each of the RETA sites.

Our simulated 'optimal' decision making framework presumes that the decision regarding which fuel to switch to, and when, is purely about the change in capital and operating expenditure arising from the project. The various sources of our estimates used in our modelling are outlined in Appendix B, and some are developed in more detail in Sections 8 and 9. Using discounted cashflows analysis, at an appropriate discount rate, we can determine the 'net present value' (NPV) of the combination of up-front capital costs and changes in ongoing operational costs (including the cost reduction from not consuming fossil fuels), tailored to each type of technology (heat pump or boiler) and fuel (electricity or biomass). We then assume that the process heat user would choose the option with the best (highest) NPV.

7.1.1 Resulting MAC values for RETA projects

The range of marginal abatement costs for Northland RETA projects are illustrated in Figure 17 below. Individual MACs have been calculated for each site's demand reduction and heat pump projects, as well as the optimal choice of fuel for boilers. These charts include all 31 confirmed and unconfirmed projects.

Figure 17 – Number of projects, and cumulative emissions reductions, by range of MAC value. Source: EECA

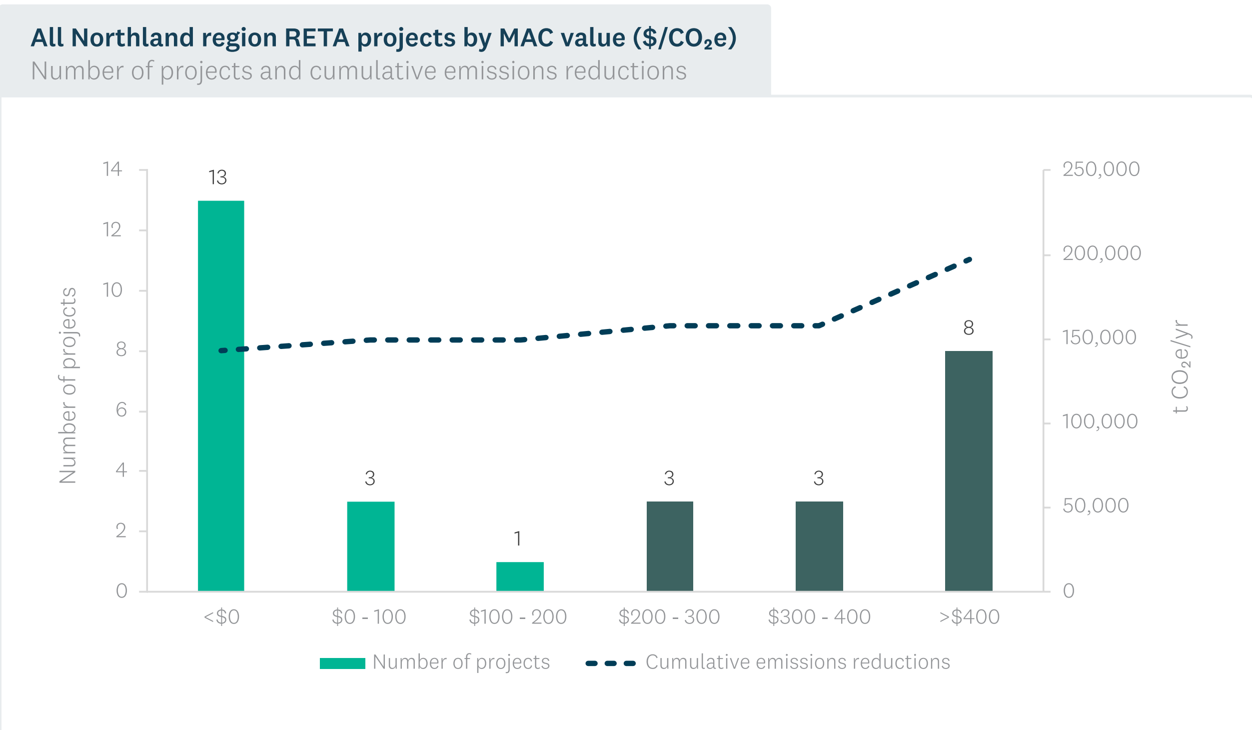
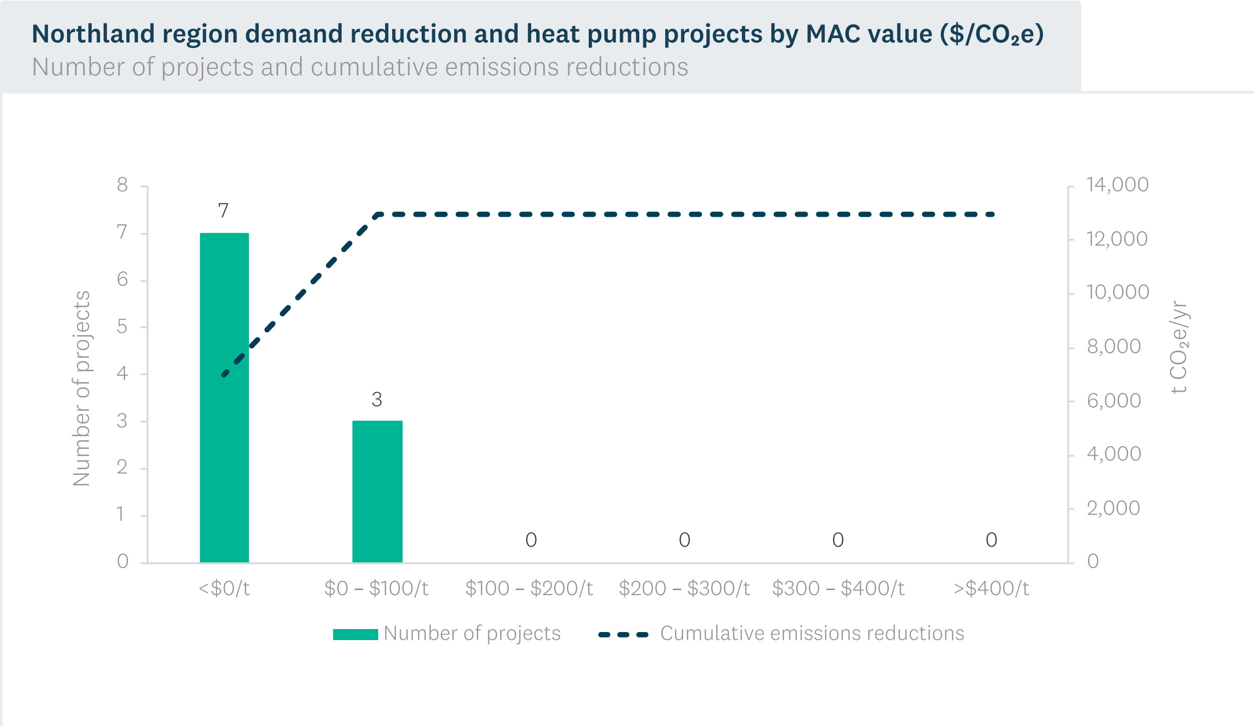


Figure 17 shows (in light green) 17 out of a total of 31 Northland projects that have MAC values less than $200/t CO_2e. These projects would have a positive net present value ('NPV') for the RETA organisations at some point in the period to 2037, if NZ ETS prices rose in line with the Climate Change Commission's Demonstration Path carbon price projections. The figure also shows that these 17 projects would deliver a 57% (149,000t CO_2e) reduction in the total RETA site emissions.

Delivering 55% of the total RETA emissions reductions, 13 projects would be economic without any carbon price.

Figure 18 shows that 10 of the 17 lower-MAC economic projects are demand reduction and heat recovery projects, delivering 12,977t of emissions reductions.

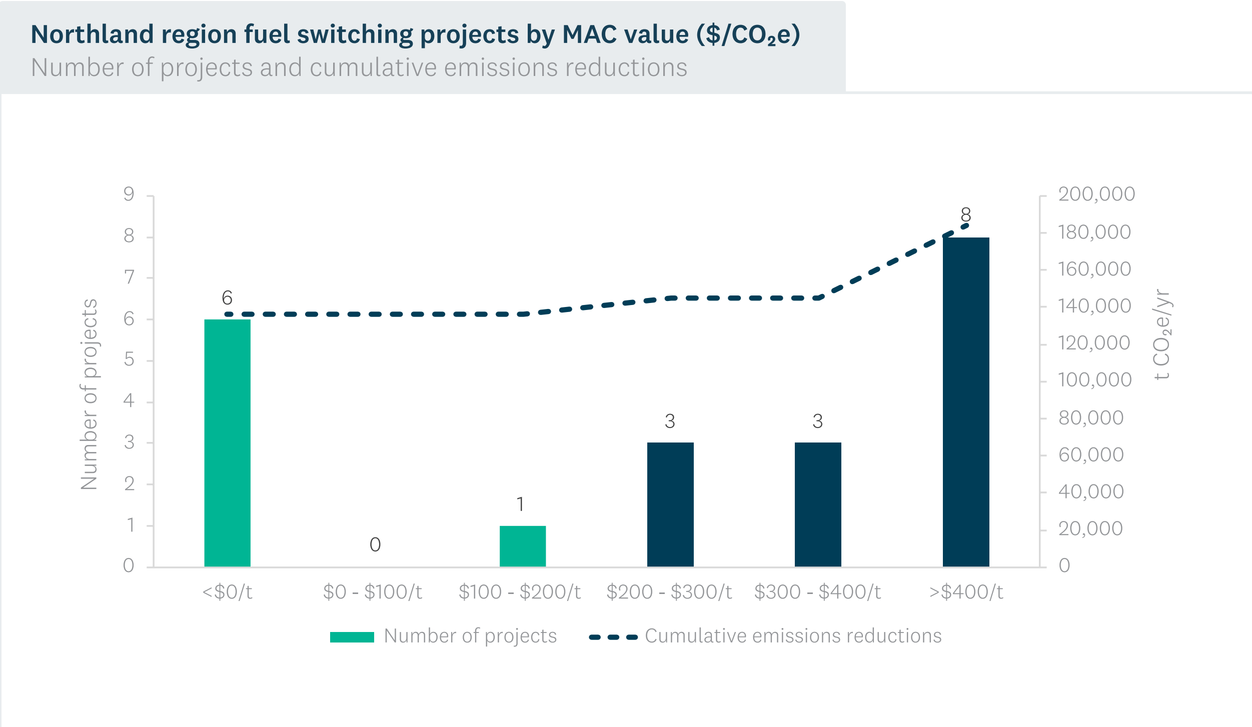
Figure 18 – RETA demand reduction and heat pump projects by MAC value. Source: EECA

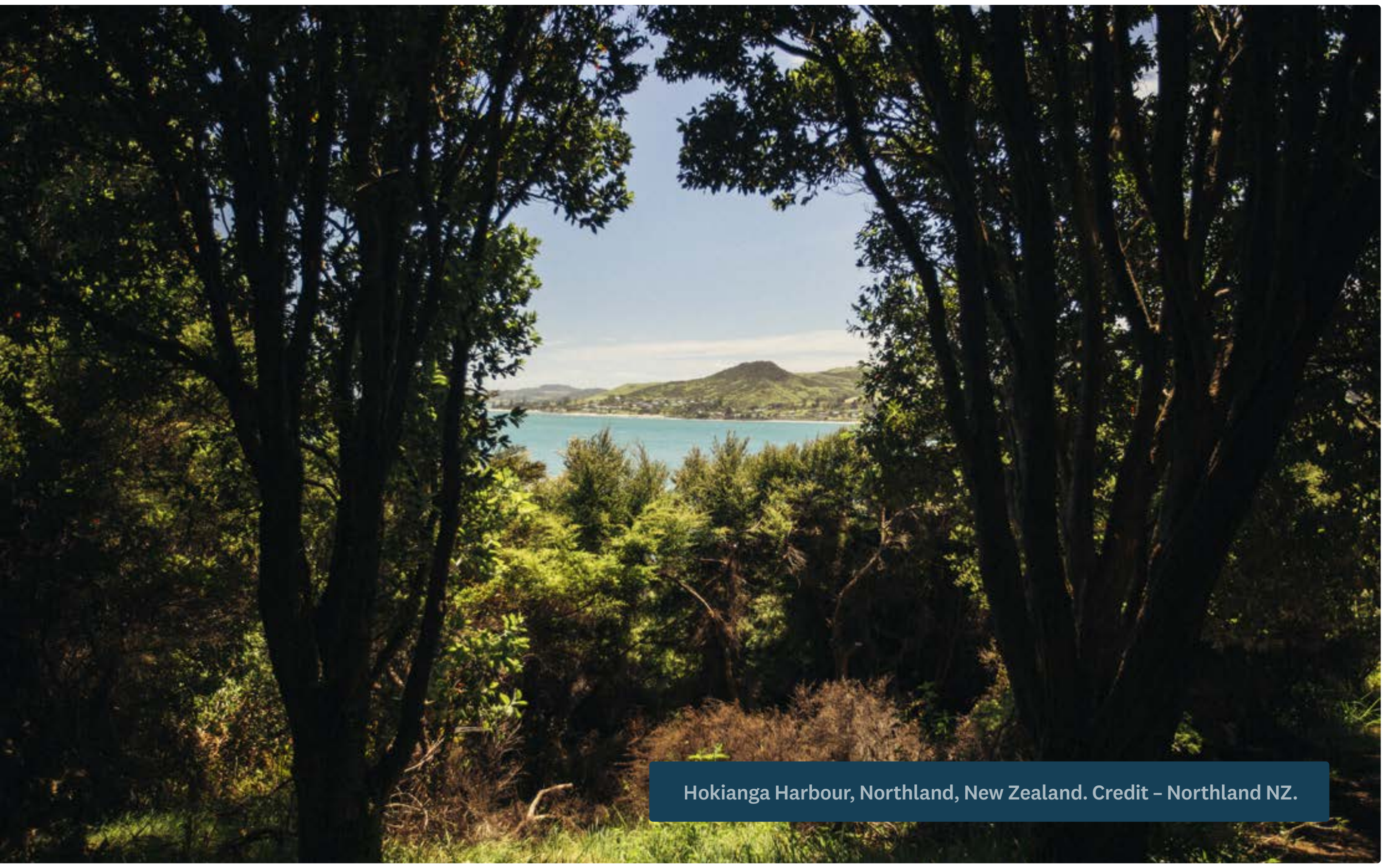


Most of fuel switching projects in the Northland region have higher MAC costs (Figure 19) reflecting the various combination of site-specific factors, such as the lumpy nature of potential electricity upgrade costs as calculated in Section 9 (where relevant); the operating profile over the year; and the overall utilisation of the boiler capacity.

Seven fuel switching projects are economic within the period, delivering 136,237t of emissions reductions – 52% of the total RETA process heat emissions. Three involve switching to biomass fuel, and four involve switching to heat pumps.

Figure 19 – RETA fuel switching projects by MAC value. Source: EECA





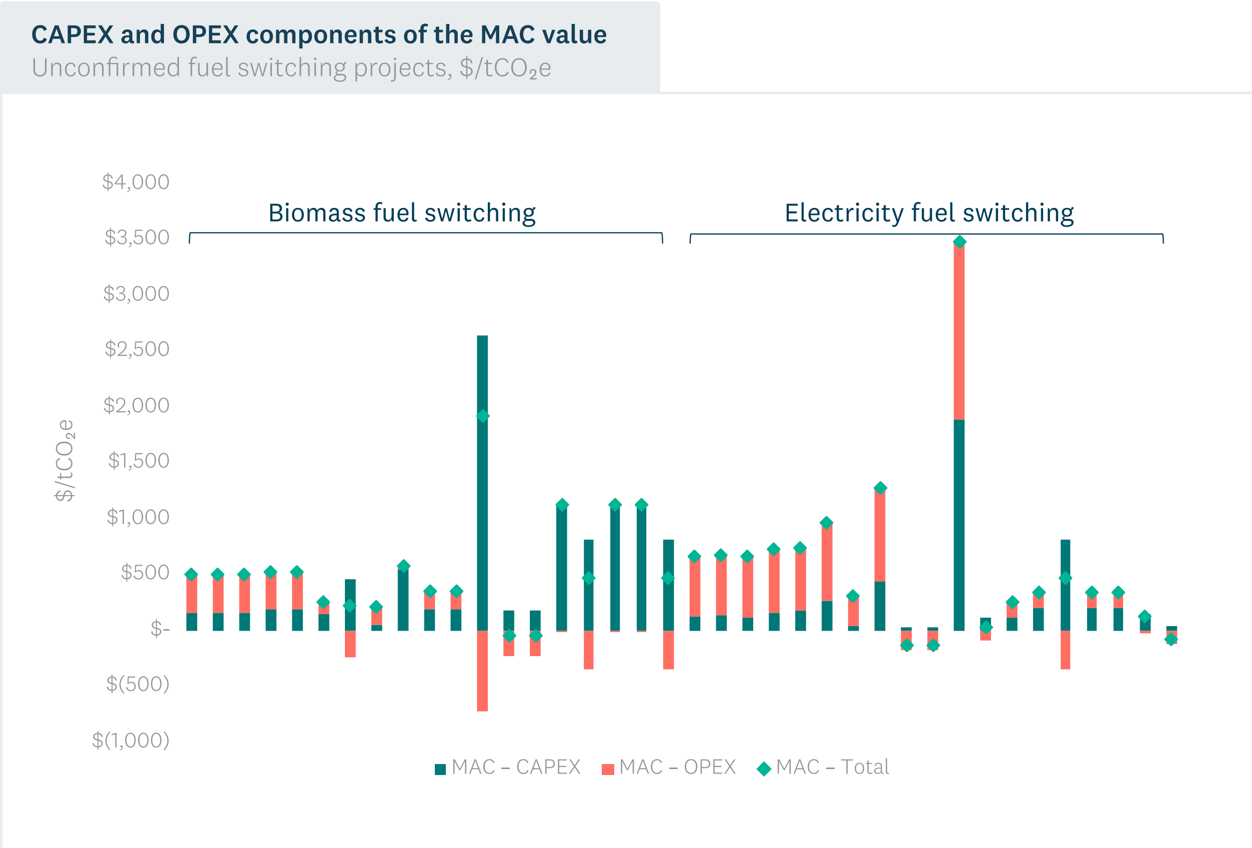
Hokianga Harbour, Northland, New Zealand. Credit – Northland NZ.

7.1.2 What drives Northland's MAC values?

Particularly for projects that have higher MAC values, there could be a range of ways cost reductions could be achieved to make the remaining projects more viable over the term of the RETA: for example, securing access to lower cost biomass resources, or enabling plant flexibility to reduce the cost of electricity connections and/or electricity consumption.

To better understand what components of a project's overall costs is driving the MAC values for Northland RETA sites, Figure 20 illustrates the MAC values for each of the 20 unconfirmed fuel switching projects, across the two fuel options. The MAC value is separated between the project's up-front capital costs ('CAPEX') and operating costs or benefits ('OPEX').

Figure 20 – CAPEX and OPEX MAC values for unconfirmed fuel switching projects. Source: DETA



Generally, across these Northland region RETA projects, the capital component of the MAC value is much higher for biomass projects than for electrification projects, the latter being exclusively through the use of heat pumps. This is due to the higher cost (per-MW) of biomass boilers compared to heat pumps. However, the operating expense component of Northland region electricity MAC values tends to be higher than biomass, the net result of two effects:

- Retail electricity costs (including network charges) are higher (per unit of energy) than biomass; but
- If they can be used, heat pumps are more than four times more efficient than biomass boilers, and therefore reduce more fossil fuel consumption per-MW than biomass boilers.

Note that the operating component of the MAC value is the net effect of the reduction in fossil fuel cost, and the cost of procuring the biomass or electricity. As shown in Figure 24, there are some situations – particularly where expensive fuels such as diesel or LPG are being used – where the net OPEX effect can be negative, because the low emissions fuel is overall cheaper than the fossil fuel, even without accounting for the impact of carbon emissions.

The overall relativity of electricity and biomass MAC values, shown in Figure 20, is very context dependent – especially dependent on whether a heat pump can be used, or if an electrode boiler is required for a switch to electricity. We also reinforce that the relativity of biomass and electricity MAC values in the Northland region is based on the regionally specific assumptions this report has used as described above. It is not a general commentary on the relative economics of biomass versus electricity.

As will be reinforced in both Section 8 and Section 9, the costs used in our MAC value calculations could be improved on in a range of ways – for example, using flexibility to reduce the impacts on electricity networks (and therefore network charges) or accepting a lower level of security of supply.

Okiato Point, Northland, New Zealand. Credit – Top Energy.

7.2 Indicative Northland pathways

Indicative pathways for decarbonisation have been prepared on the following basis. Projects that are known to be committed by an organisation (e.g. funding allocated and project planned) are locked in for all pathways. Where organisations do not have a confirmed project, the following constraints were applied to the methodology:

- All low to medium temperature (<300°C) coal boiler decarbonisation projects are executed by 2037 in line with the National Policy Statement (NPS) for greenhouse gas emissions from industrial process heat that came into effect in July 2023, which prohibits greenhouse gas emissions from these boilers after 2036[29].
- All other unconfirmed projects are assumed to occur in 2049 in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act. This means that any projects that are still not 'economic' using our MAC criteria (illustrated in Figure 17) by 2049, are assumed to be executed in 2049.

The pathways were then developed as follows:

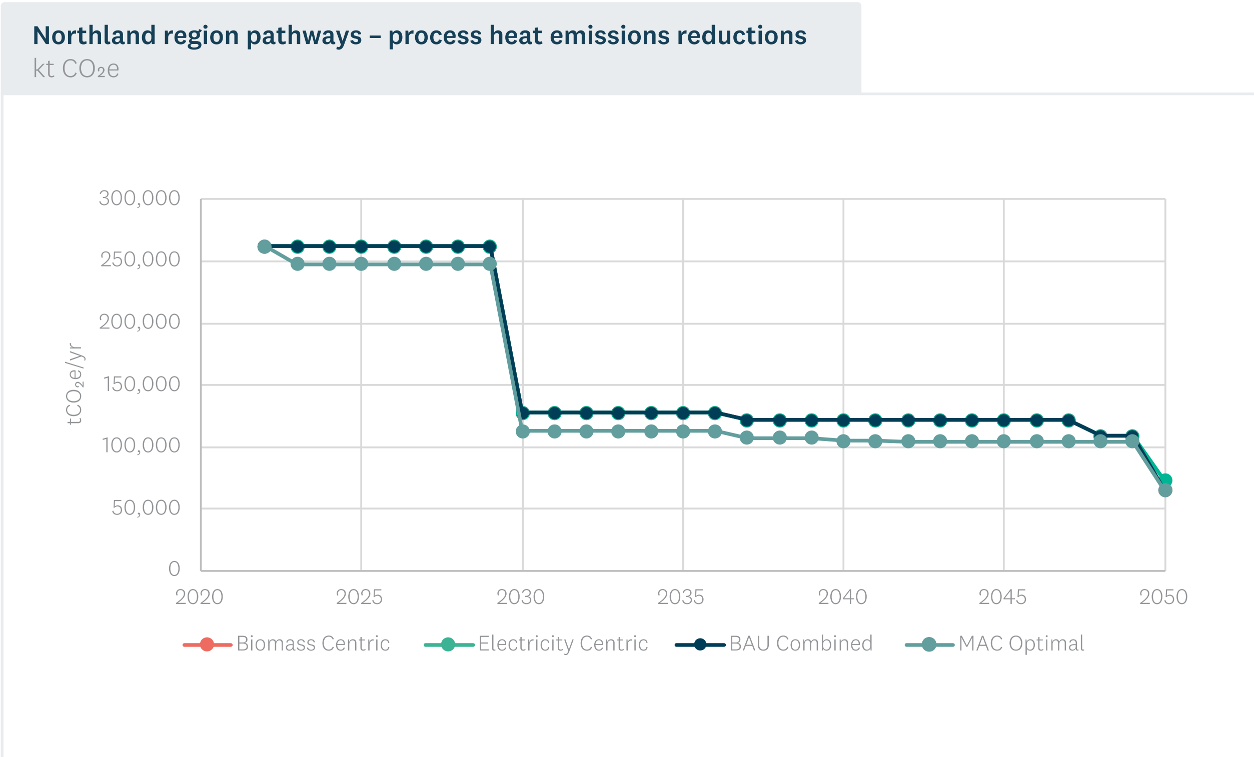
Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass where possible, with the timing based on the criteria above.
Electricity Centric	All unconfirmed site fuel switching decisions proceed with electricity where possible, with the timing based on the criteria above.
BAU Combined	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project; with the timing based on the criteria above.
MAC Optimal	Each site switches to a heat pump or switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of the Climate Change Commission's future carbon prices in their Demonstration Path. If the MAC value does not drop below the ten-year rolling average, then the timing criteria above is used.

29 See https://environment.govt.nz/publications/national-policy-statement-for-greenhouse-gas-emissions-from-industrial-process-heat-2023/. The new National Environmental Standard which supports the NPS also places increased restrictions on process heat boilers burning fossil fuels other than coal.

7.2.1 Pathway results

By 2037, all pathways eliminate between 51% and 57%of annual process heat emissions in the region (a reduction of between 140,384t and 154,782t t per annum). By, 2050, all pathways eliminate 75% of annual emissions reductions compared to today (a reduction of 197,316t per annum) but at a different pace (Figure 21). The remaining emissions in 2050 primarily relate to the burning of shredded tyres at Golden Bay Cement.

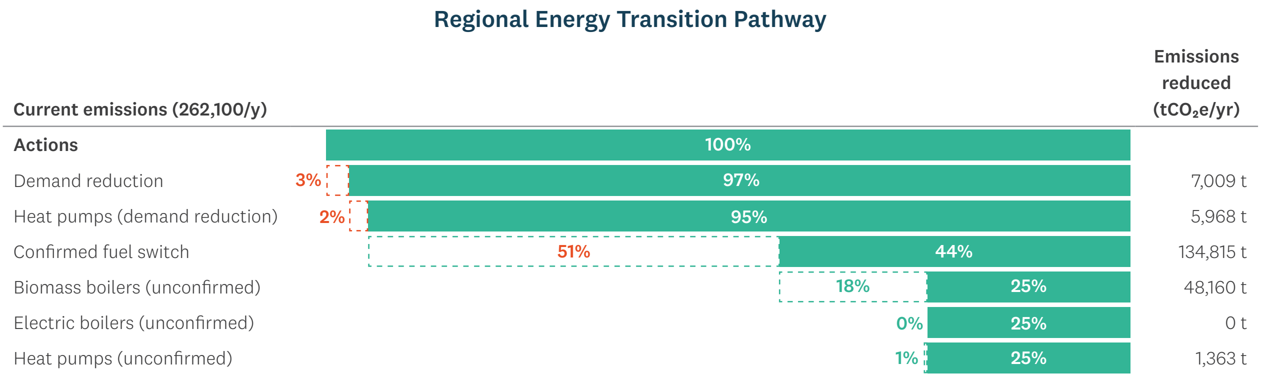
Figure 21 – Emissions reduction trajectories for different simulated pathways. Source: EECA



All pathways achieve most of their annual emissions reductions in 2030, however the reduction in MAC optimal pathway is slightly higher – 57% compared to 51% in the fuel Centric pathways. On a cumulative basis, this means that the MAC Optimal pathway delivers most emissions reductions over the period to 2050. The cumulative difference between the MAC Optimal and the fuel-centric pathways is 392kt CO_2e – exclusively long-lived greenhouse gases – across the period 2022 – 2050.

Figure 22 breaks down the MAC Optimal pathway by the same components used in Figure 16. Most of the emissions reductions are achieved through switching to biomass boilers, 5% through demand reduction and heat recovery (heat pumps), and 1% using heat pumps.

Figure 22 – MAC Optimal pathway by technology used. Source: DETA




Taipa, Northland, New Zealand. Credit – Top Energy.

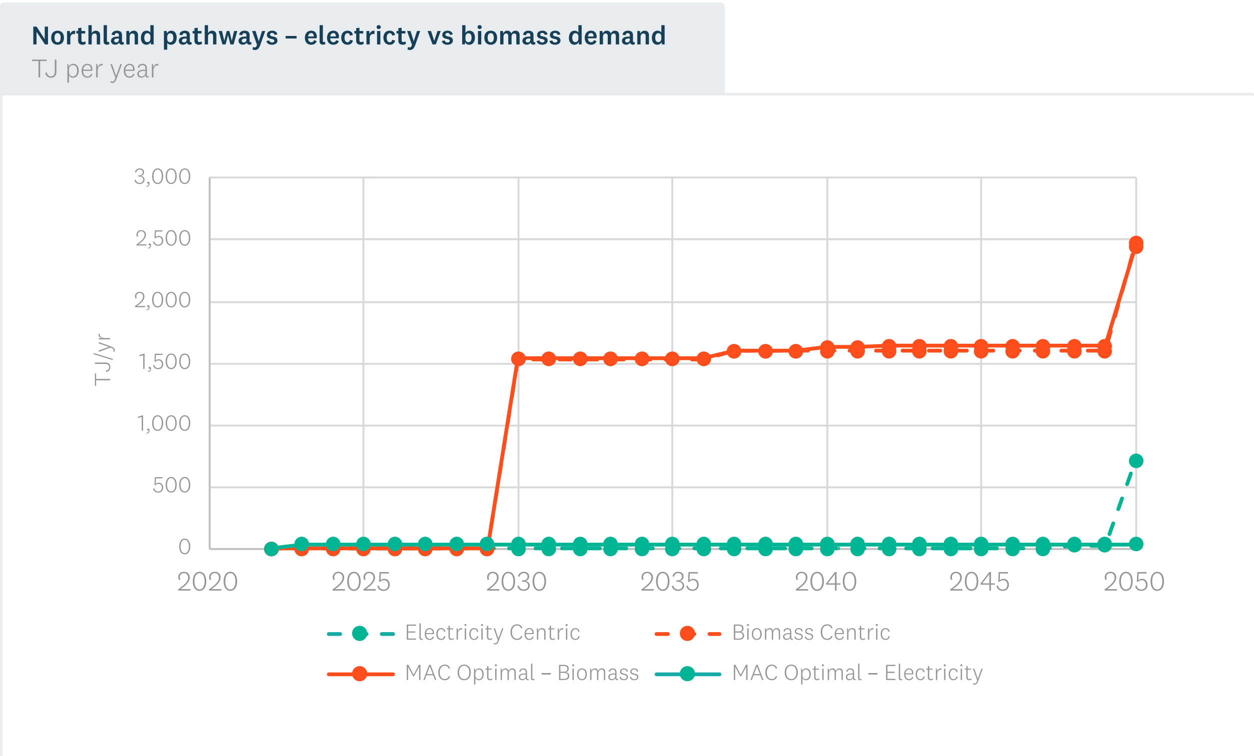
7.3 Pathway implications for fuel usage

We can now compare the trajectory of demand for biomass and electricity arising from the various Northland pathways. Below we compare the growth in demand in two of the pathways:

- Biomass Centric, Electricity Centric
- MAC Optimal

As shown in Figure 23, the Biomass Centric and Electricity Centric pathways deliver the highest demands for each fuel – 2,471TJ for biomass and 714TJ for electricity in 2050. The pathways that use MACs to determine fuel switching decisions result in a different set of fuel decisions, with around 99% of the energy needs supplied by biomass (with a consumption of 2,445TJ of delivered energy), and only 1% of energy needs supplied by electricity (with 34TJ of delivered energy).

Figure 23 – Simulated demand for biomass and electricity under various RETA pathways. Source: EECA



The pathways show the planned decision of Golden Bay Cement to switch to 1,535TJ of biomass in 2030.

The sheer dominance of biomass reflects its lower overall cost as a fuel for large industrial and dairy projects, which require high temperature boilers for their process heat.[31] Compared to sites analysed in the South Island, biomass is lower cost, due to the plentiful forestry resources in Northland. Further, the retail cost of electricity is higher than in the South Island, due to less favourable fuel-switching 'special pricing' deals being available from electricity retailers.

We now consider the implications for each fuel in more detail.

[31] That is, they can't fuel switch using high efficiency heat pumps alone.

7.3.1 Implications for electricity demand

Figure 24 shows the growth in electricity demand in each of the pathways.

Figure 24 – Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA

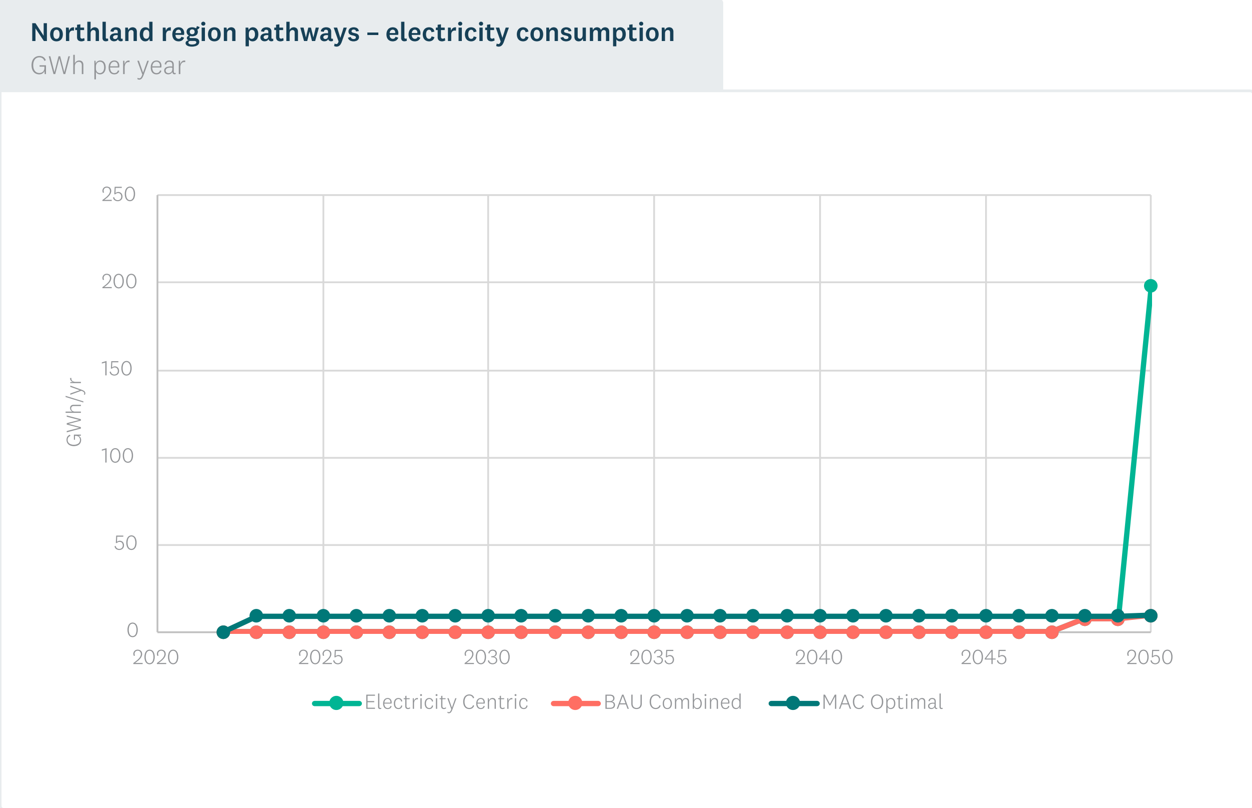
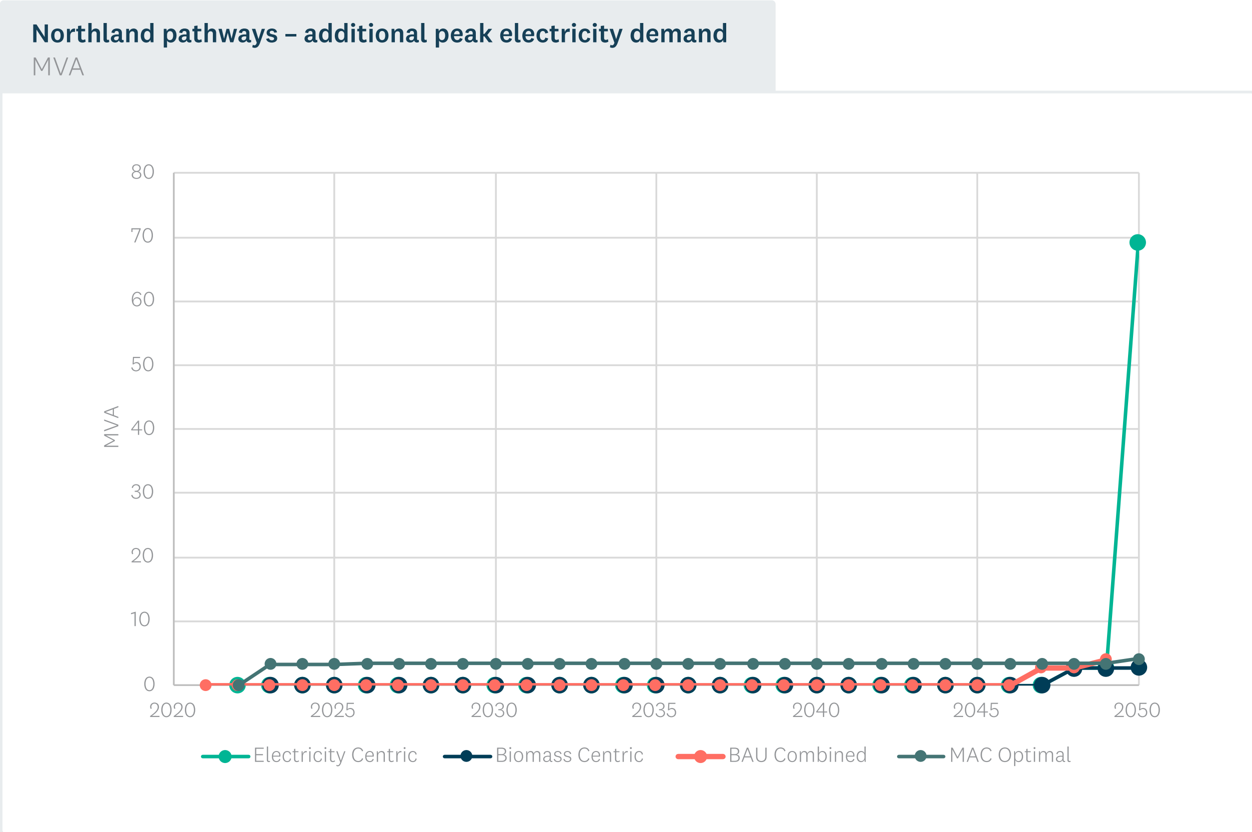


Figure 24 shows that the use of MACs to simulate decision making only slightly accelerates unconfirmed projects, the two largest of which consume 1.4 GWh p.a. (Northland Polytechnic and Whangarei Aquatic Centre). In a Centric world, these projects would not be switched until 2048, whereas the MAC criteria see it convert to electricity in 2023.

A more critical aspect of the process-heat driven growth – and timing of growth – in electricity demand is the impact it has on network planning. Networks will be more interested in the impact on potential peak demand than energy consumption per se. Figure 25 illustrates the potential increase in peak demand, for each pathway. This is determined by adding together the maximum demand from each boiler and heat pump, without taking account of demand diversity. The impact of demand diversity is considered in Section 9.4.

Figure 25 – Potential peak demand growth under different pathways. Source: EECA



Over the period 2024-2036, the electricity demand from new heat pumps could be up to 3.4MVA depending on the pathway, representing an increase of up to 2.2% and 4.3% in the local EDB peaks (Northpower and Top Energy respectively). In 2050, the Electricity Centric pathway increases significantly (an increase of 66MVA in one year), with a resulting demand that would represent a 23% increase compared to today. EDBs will likely find annual increases of this magnitude, requiring a significant degree of planning to have any investment timed in advance of the increase in demand. That said, we note that this large increase in demand in one year is an artefact of our modelling assumptions, and we do not believe it is reflective of reality.

We reinforce these contributions to peak network demand are upper bounds (in each pathway), as they assume that all electrified boilers reach their maximum consumption at the same time of day and time of year (i.e. coincident peak demand). This is a conservative assessment, as there is likely to be a diversity amongst peak demands as outlined in Section 9.4; as well as commercial incentives to shift this peak demand away from the time the wider network peaks. The impact of flexibility and diversity on capacity upgrades depends on a range of factors that need to be considered more fully. Appendix C discusses the opportunities and benefits from enabling flexibility in more detail.

7.3.1.1 EDB analysis

The implications of these peak demand growth scenarios will be different for each of the distribution network companies, as their existing networks have different levels of spare capacity (as outlined above).

Section 9.3 highlights that there can be material differences between adjacent networks in terms of unused capacity; these differences exist for a range of historical reasons. This can lead to quite different relative network upgrade costs for projects connection in each region. Table 7 shows how the connections potentially affect each EDB's network.

Table 7 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
North Power	65.8	$17.3	4.0	$0.1
Top Energy	3.4	$0.0	0.1	$0.0
Total	**69.2**	**$17.3**	**4.1**	**$0.1**

Table 7 shows that the Northpower network will experience the largest increase in process heat-related electricity demand in both the Electricity Centric and MAC Optimal pathways. The connection cost estimates suggest that each EDB will spend up to $17M connecting new process heat plant to the local networks, depending on the pathway.

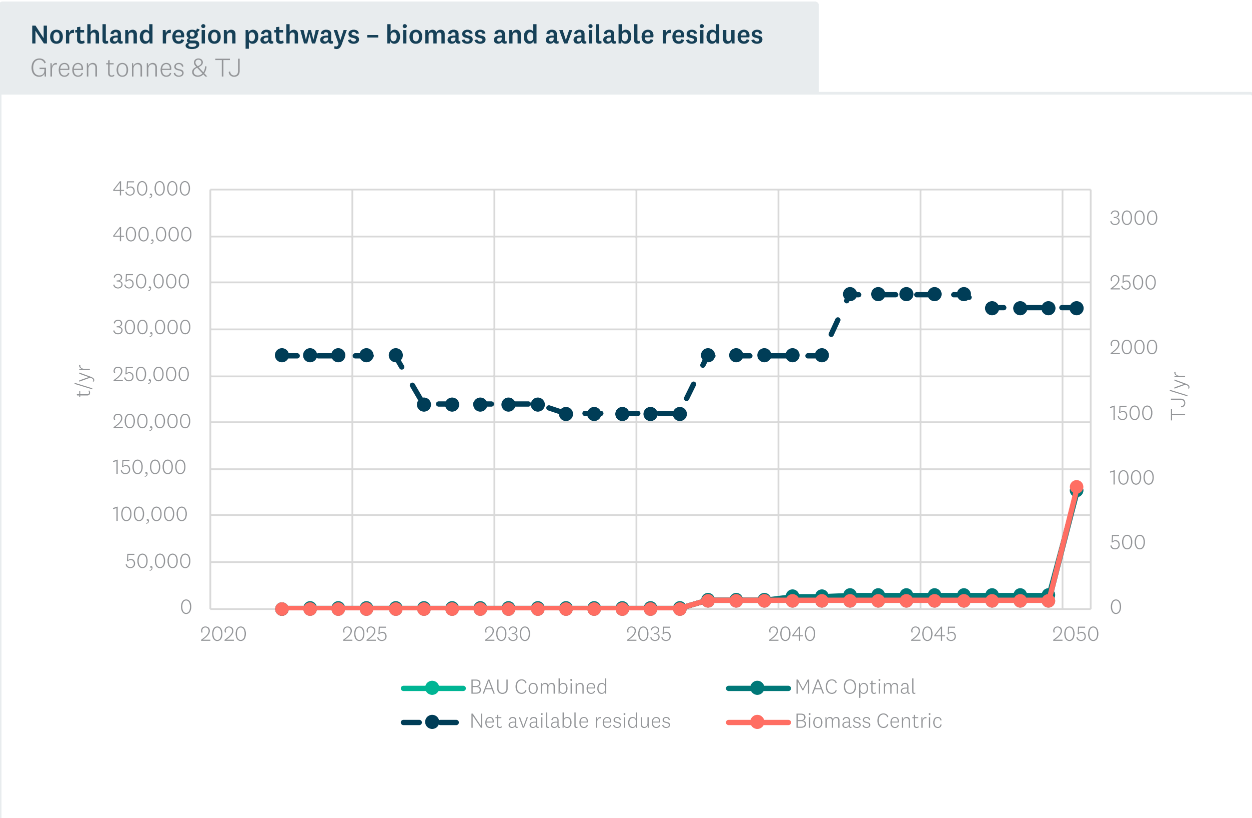
Note that the network upgrade costs presented in Table 7 are total construction costs and may not necessarily reflect the connection costs paid by RETA organisations, as they may be shared between the EDB and the new process heat user. The degree of sharing ('capital contributions') depends on the policies of individual EDBs, as discussed further in Appendix C. These costs also exclude the ongoing network charges paid by each process heat user that electrifies their process heat.

7.3.2 Implications for biomass demand

Figure 26 shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the pathways. Note that the chart excludes biomass demand from the Golden Bay Cement, as this biomass will be primarily sourced from construction and demolition waste streams.

Biomass demand is similar across all pathways, with the MAC pathway using 30TJ and 42TJ more than the other pathways from 2040 and 2042 respectively.

Figure 26 – Growth in biomass demand from pathways. Source: EECA



We can also see that the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed[32]) are more than sufficient to meet the biomass demand under all pathways. This is shown as the dashed line in Figure 32. Note that the assessment of these resources is based on a more conservative estimate of recoverable harvesting volumes, as outlined in Section 8.5.2.

The potential use of harvesting and processor residues for biomass projects in any of the pathways above is a significant commercial opportunity for organisations that could provide the sourcing, collecting, processing, storing and delivery to process heat users. Based on EECA's analysis – explained in Section 8 in more detail – the cost of the underlying fibre alone could be up to $73M over the next 15 years.[33]

32 See Section 8.6

33 Assuming an underlying cost of collecting these residues out of the forest of $10/GJ, as outlined in Section 8.

7.4 Sensitivity analysis

EECA acknowledges that there are a range of factors which determine each organisation's final decision on fuel switching. The NPV of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, competing priorities, risk appetite, uncertainty about future costs, supply chain constraints and labour market implications are examples of the myriad factors that must be considered when deciding when to switch away from fossil fuels, and which fuel to choose.

This report does not speculate on those factors. However, understanding how sensitive the fuel choice is to the commercial factors may go some way to providing confidence of the best decision, both in terms of fuel choice, and timing. This RETA report has outlined some of the uncertainties related to both up-front and ongoing fixed and variable costs, for example:

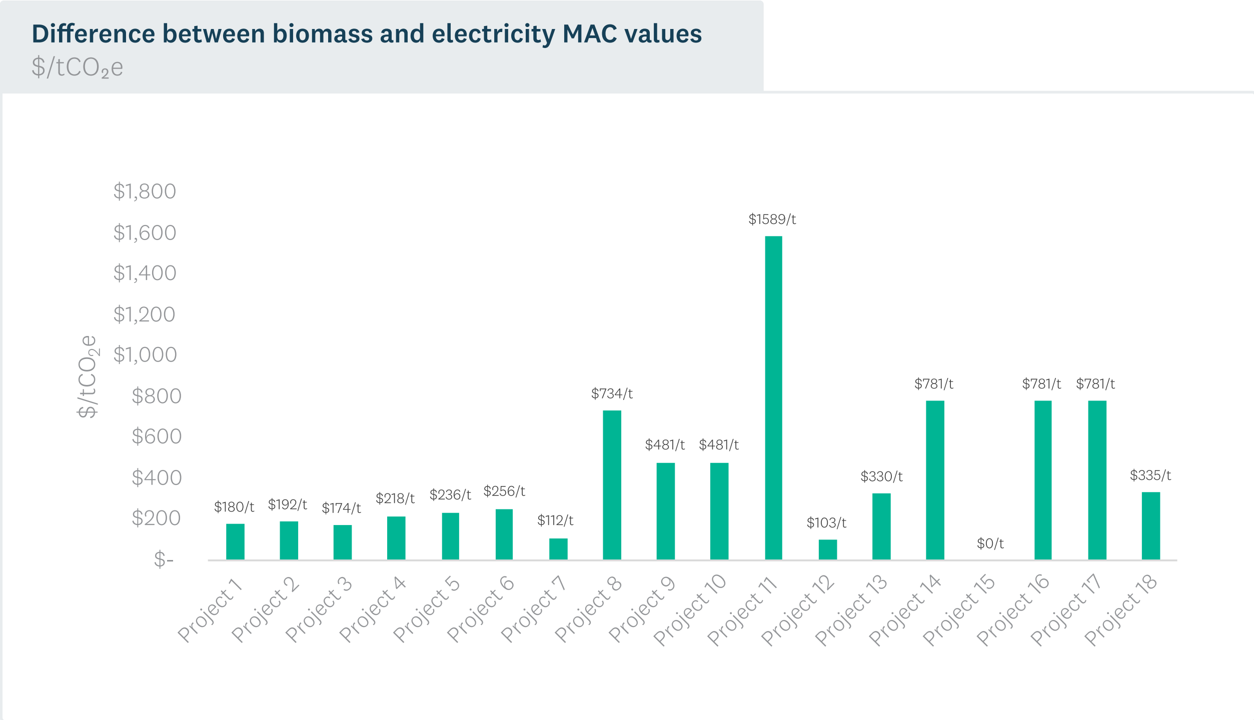
- The uncertainty in the underlying variable fuel costs (electricity and biomass). Electricity has a combination of fixed (per-annum use-of-network charges) and variable costs.
- The uncertainty regarding the magnitude of up-front upgrade costs required to connect an individual RETA site to the electricity network (including the degree to which flexibility in plant consumption could reduce these costs – see Appendix C).
- The uncertainty in the quantity of sustainable biomass that could be practically brought to market and made available as a source of bioenergy.

In terms of fuel switching, one way to consider how sensitive the fuel switching decision is to variability in underlying costs is to look at how close the MAC values for the competing fuels are.

For the 18 RETA projects where the fuel switching decision is still unconfirmed, and both electricity and biomass is being considered, Figure 27 shows that five of these projects have differences between electricity and biomass MAC values of between $100/t and $200/t. For one project, there is no MAC different between converting to biomass or using a heat pump, so small changes in underlying costs could easily change the decision.

Puketona, Northland, New Zealand. Credit – Top Energy.

Figure 27 – Difference between electricity MAC value and biomass MAC value; sites that are considering both options. Source: EECA.



It would take a considerable change in underlying costs to change the optimal fuel decisions for the remaining projects, but for these five, plausible deviations from EECA's input estimates used in this analysis could change the decision. To illustrate the sensitivity of these MAC values for the 18 sites in Figure 31:

- A 20% change in up-front capital costs (including network upgrade costs) for either electricity or biomass can change the MAC value of fuel by around \$27/t CO_2e on average, and up to \$80/t for one project.
- A change in the incremental[34] operating costs (including fuel procurement) of 20% could change the MAC value by \$45/t CO_2e on average, and over \$100/t for four projects.
- Most of the potential biomass users are located around 80km away from the assumed hub[35], and some more than 100km. For the purposes of calculating the MAC values in Figure 31, the cost of transport from the hub to each process heat user was estimated at \$3/GJ, based on an average distance of 80km. However, three sites were much closer to the hub (22km on average) and would have experienced transport costs closer to \$1/GJ. This difference in transport costs equates to \$22/t CO_2e on the MAC value, demonstrating how sensitive MAC values are to some costs.

Given this, plausible changes in these costs may change a small number of fuel switching decisions. However, even if the fuel switching decision didn't change, the change in MAC could accelerate or delay the timing of the fuel switch, in the MAC Optimal pathway.

[34] This is not the same as saying that a 20% change in electricity price, or biomass price, will have this effect. As outlined above, the OPEX component of a MAC calculation is the difference between the cost of continuing to use coal, and the cost of switching to electricity or biomass. Here we are changing the magnitude of the difference, which would require a greater than 20% change in the cost of the fuels.

[35] As discussed in section 8.7, we suggest this hub is located in Ngāwhā.

These illustrative changes also highlight that, all things being equal, changes in the lifetime OPEX of a fuel switching investment has a larger impact on the MAC value than the upfront CAPEX. While the CAPEX component requires the greatest focus in terms of the funding and financing of the investment, cost of fuel over the 20-year lifetime of the decision is critical.

Beyond up-front capital and ongoing fuel prices, there are a range of other factors which may change the MAC value and therefore the decisions made by process heat users. For example, a restriction in the availability of sustainable biomass may arise, meaning organisations who commit to decarbonisation late in the RETA period are only able to electrify.

To test the impact of potential changes on the pathways, EECA undertook the following four sensitivities:

- Two sensitivities relating to the retail price of electricity, using Energylink's 'low' and 'high' retail price scenario, described more fully in Appendix C.
- A 50% change in the capital cost of any network upgrades required to accommodate a fuel switch to electricity.
- Amending the decision criteria for the timing of a decarbonisation investment, from when the average of the 10 year carbon price forecast exceeds the MAC, to when the current year carbon price exceeds the MAC (as discussed in Section 7.1.2).

We discuss these sensitivities below.

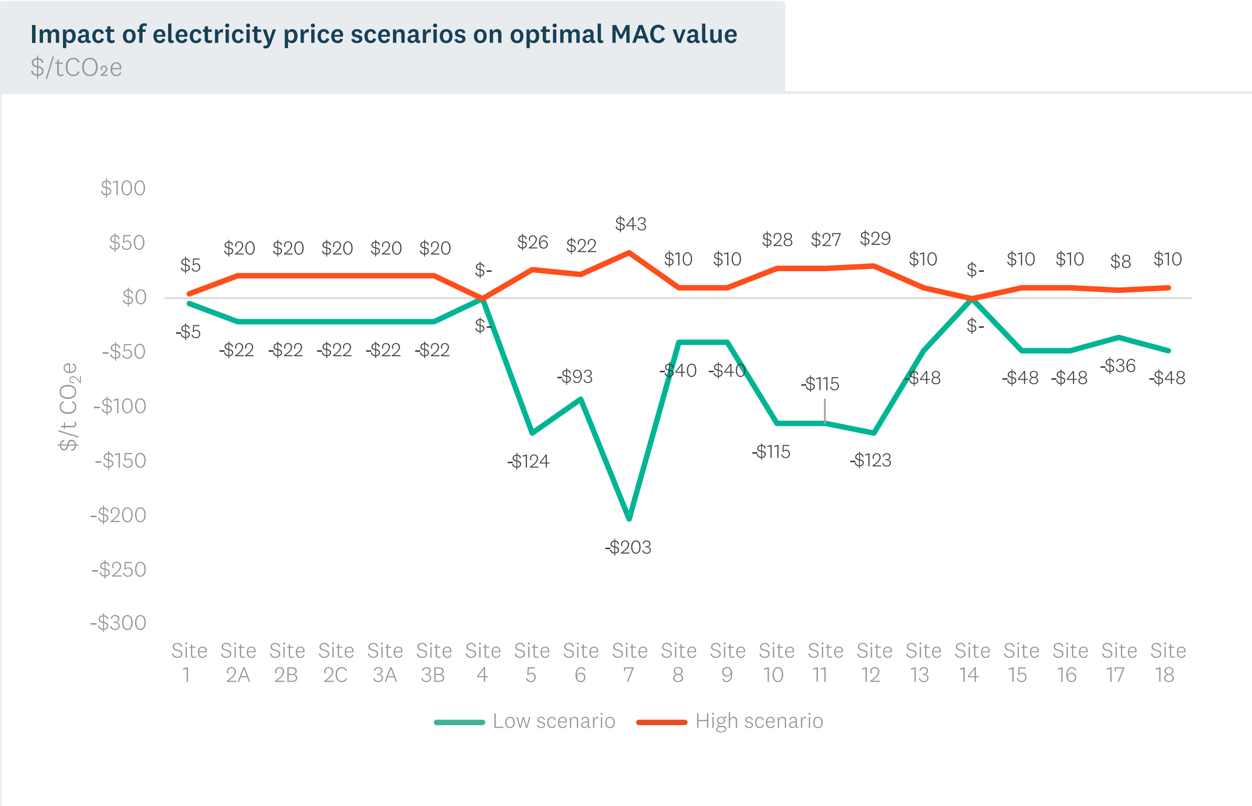
Taipa, Northland, New Zealand. Credit – Top Energy.

7.4.1 Lower and higher electricity prices

As discussed in Section 9.2.2.1, there are a range of factors that could lead to electricity prices that are materially different to the 'central' scenario used for the analysis in this chapter. As discussed in that section, we presented a 'high' and 'low' price scenario.

Using the 'high' and 'low' scenario in the MAC calculations led to modest changes for most projects, and significant changes to six projects in the 'low' scenario., as shown in Figure 28.

Figure 28 – Impact of EnergyLink's electricity price 'low scenario' and 'high scenario' on MAC values. Source: EECA



The 'low' scenario closed the gap between biomass and electricity for most unconfirmed projects, and led to two changes in fuel choice, from biomass to electricity. The 'high' price scenario didn't trigger any project to change its fuel switching decision from electricity to biomass.

7.4.2 A 50% change in the cost of network upgrades to accommodate electrification

For the projects that required upgrades to the electricity network in order to allow them to switch to electricity (either an electrode boiler or a heat pump), we evaluated a 50% increase and decrease in the cost of these upgrades.

Neither a 50% increase or decrease changed the optimal fuel switching decisions for these sites. Figure 29 shows the impact of a 50% increase in the cost of network upgrades on the MAC value (a 50% decrease would have the same effect)

Figure 29 – Impact of a 50% increase in network upgrade costs required to accommodate fuel switch to electricity; $/tCO_2e. Source: EECA

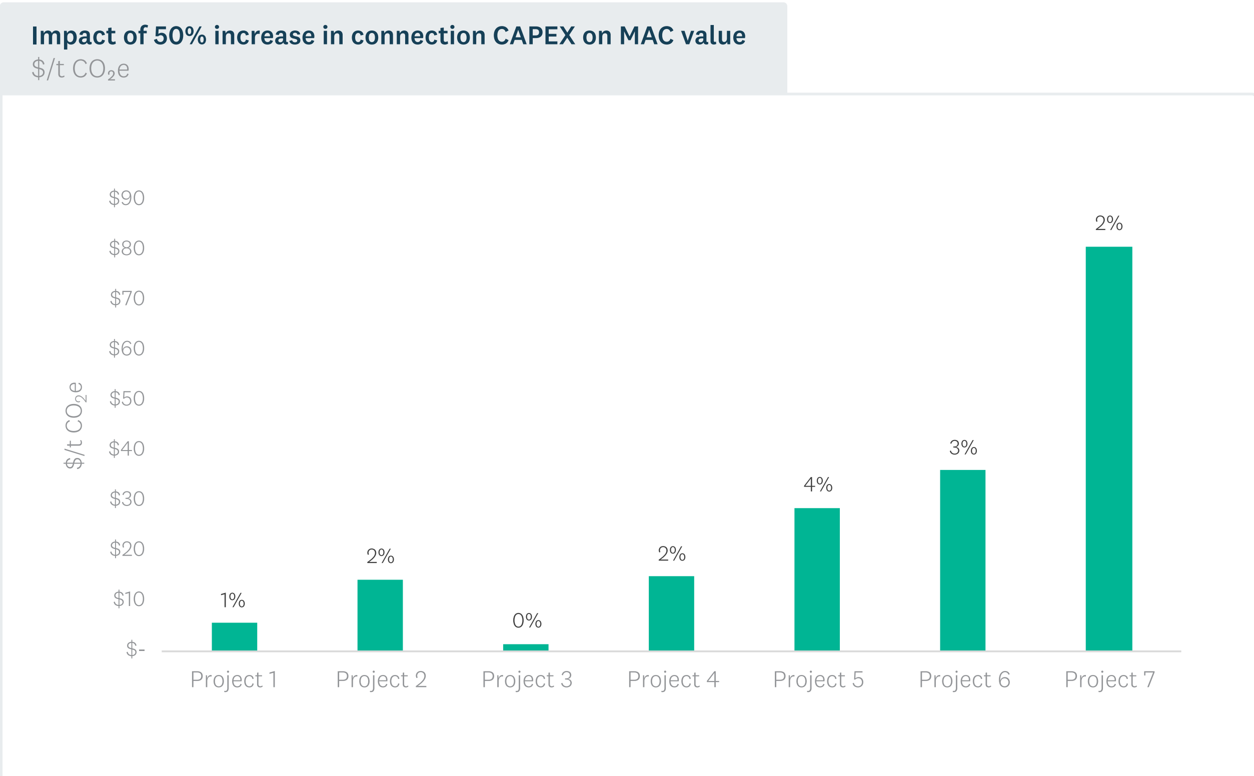
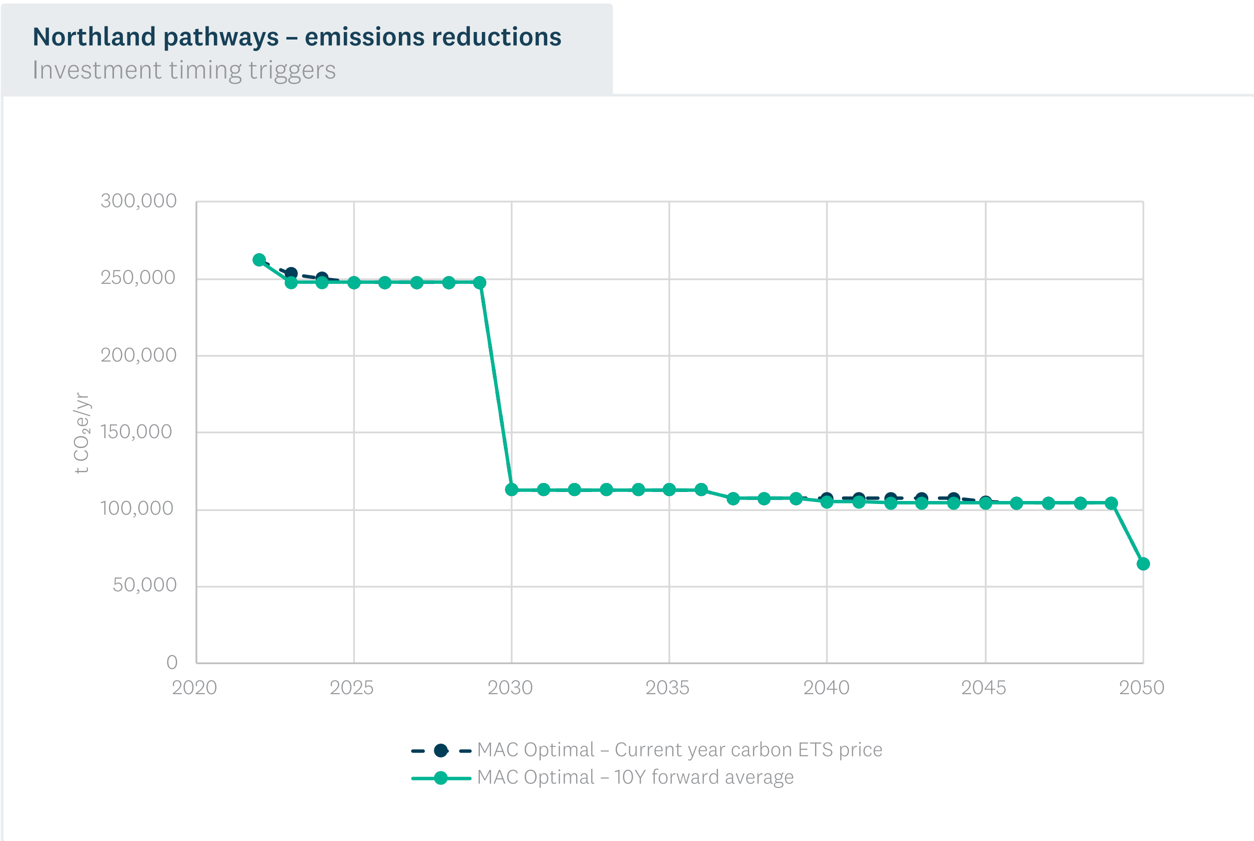


Figure 29 shows why the change in network connection cost doesn't alter decisions – while the absolute change in MAC value ranges between $10 and $80/t for most projects, this only represents 2-4% of the total MAC value.

7.4.3 Amending the decision criteria for investment timing

This sensitivity compared the demand for biomass and electricity under two decision making criteria – the 10-year future average carbon price (used for the MAC Optimal pathways above) versus simply waiting for the present-day carbon price to exceed the MAC value of the project.

Figure 30 – Comparing MAC-based decision making criteria. Source: EECA



The chart shows that the ‘current year’ criterium slightly affects fuel switching decisions (to biomass) during the time horizon: some projects are delayed from 2023 to 2024/2025, and other projects are delayed from 2040 and 2042 to 2045/2046.

8 Bioenergy in the Northland region

8.1 Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the Northland region as a potential source of bioenergy for process heat fuel switching. While there are other sources of biomass (e.g. landfills), the focus is on major sources that could collectively provide up to 1,045,589t per annum[36] – which would be the demand should all RETA sites[37] elect to switch to biomass for process heat.

Factors that need to be considered when determining the sustainability of biomass from forestry are outlined. The approach is to:

- Consider the total availability of biomass from forestry in the region, including those sources that are not currently being recovered from, for example, in-forest harvesting operations, to obtain a theoretical potential for locally sourced biomass for process heat. We adopt both a top-down and bottom-up (via interviews with forest owners) approach to this. The bottom-up analysis provides an assessment of existing usage of woody biomass for bioenergy, as well as of how the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets.
- Expert judgement is applied to allow for a more realistic assessment of the volumes of harvesting residues that can be practically recovered.
- Highlight the existing domestic and international markets for the harvested wood, either for timber products or existing demand for bioenergy (e.g. firewood) that will likely constrain the ability to divert wood to bioenergy for process heat in the near-term.
- Consider what this analysis implies for the potential cost of delivering different types of biomass to process heat users.
- Overlay the 'MAC Optimal' and 'Biomass Centric' scenarios of process heat demand for biomass from RETA fuel switching decisions, to ascertain whether this demand could be met from near term available sources, noting that the supply of bioenergy will evolve through time.

The results give a plausible view of the medium-term availability of Northland biomass for process heat purposes, and the foreseeable economic implications of using these resources (i.e. based on what we know at the time of writing). This has the potential to help potential users make indicative commercial judgements about the attractiveness of biomass, in the quantities required, relative to other fuel switching alternatives.

[36] This is the average over the 2023-2050 period. The average over the 2023-2037 period is 887,274t.

[37] Other than those which have already confirmed, at the time of this report, they are choosing electrode boilers.

Only biomass sources within the Northland region are considered. More generally, neighbouring regions could also use biomass from the forests that are included in the Northland region RETA assessment, where transport costs and logistics make this practical. The potential for inter-regional trade in biomass will be considered when all North Island RETA reports are complete, and the entire island can be analysed.

We are aware that process heat is not the only future user of bioenergy competing with existing markets for wood. International demand for bioenergy may increase in the future, leading to countries trading in biomass. Further, and as outlined in New Zealand's Emissions Reduction Plan (ERP), biofuels are a potential low-emission alternative to existing oil-derived transport fuels, and the Plan included an action to implement a sustainable biofuels obligation.[38] This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels.

8.2 The sustainability of biomass for bioenergy

The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability – for example, depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period (compared to the natural decomposition of biomass). Diversion of low-grade export wood to domestic bioenergy has an unknown global impact (via the supply chain). Suppliers and consumers of biomass for bioenergy will want to be confident they understand any wider implications of their choices.

No formal guidelines or standards exist in New Zealand at this point. There is, however, international guidance, such as:

- The Roundtable for Sustainable Biomass, Biofuels, and Biomaterials (RSB), which states that no roundwood should be used for bioenergy.
- The International Sustainability and Carbon Certification scheme (ISCC) discusses deforestation.
- The European Union Renewable Energy Directive II (RED II), which aims to limit the risk that biofuels, bioliquids and biomass fuels trigger indirect land use change.

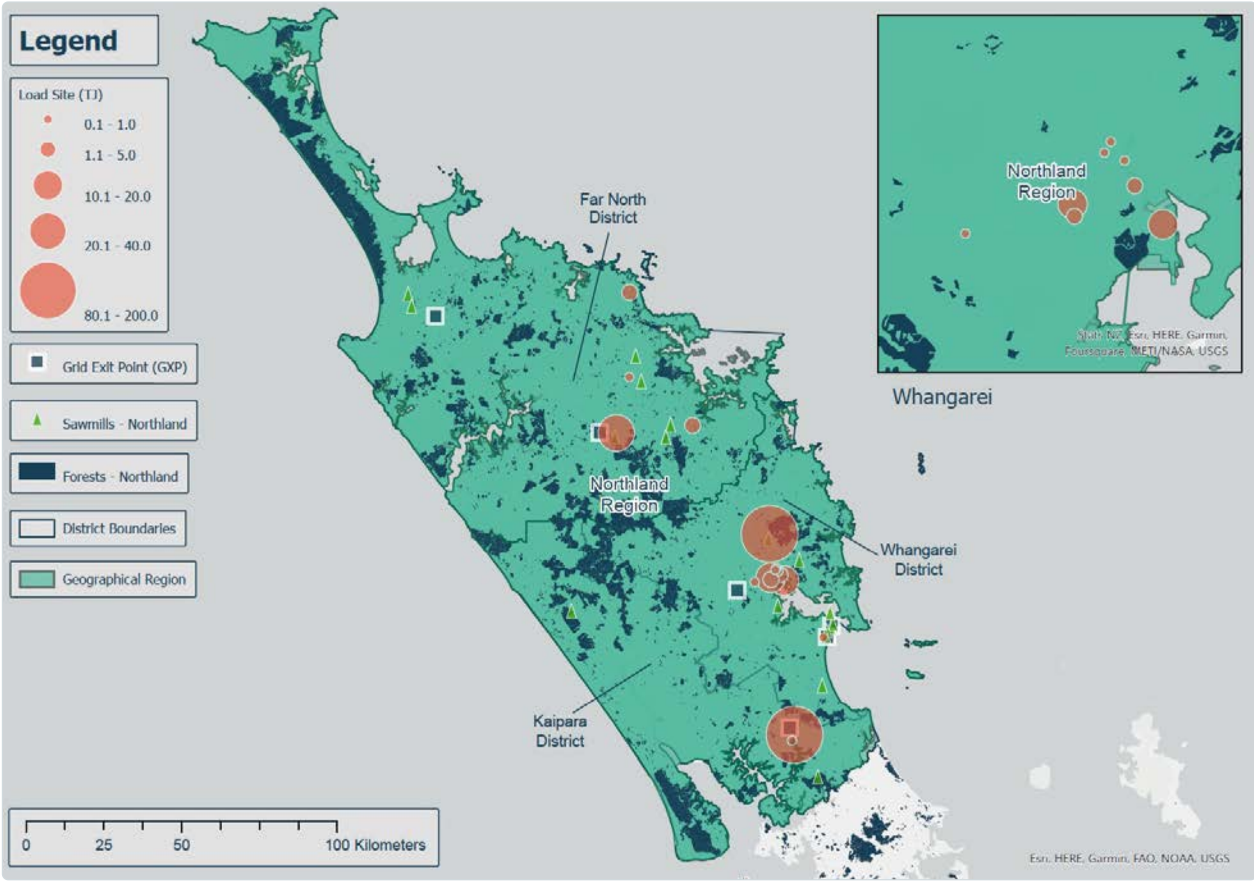
These international guidelines need to be interpreted carefully in New Zealand, in the context of our wider policy and regulatory context that may already be preventing some of the outcomes that the RSB and ISCC are seeking to avoid.

EECA recommends guidance is developed for the New Zealand context, drawing on international standards and experience.

38 We note though that although the first Emissions Reduction Plan included a sustainable biofuels obligation, this has been indefinitely paused.

8.3 Northland regional wood industry overview

Figure 31 – Map of Northland forest resources and wood processors.



The Northland region has approximately 150,705 ha of planted forests. These forests are dominated by Radiata Pine. Harvesting of minor species is unpredictable as many of these are grown as amenity species or for environmental protection reasons; consequently, minor species are excluded from the analysis.

We note that the forestry and food processing sector have partnered with Government to develop a Forestry and Wood Processing Industry Transformation Plan[39] which is focused on increasing the total area of forestry and getting greater value from wood. This includes significantly increasing the areas of trees on farms and increased domestic processing. Additional domestic processing within New Zealand may result in greater quantities of processing residues being available as an energy fuel. Increased planting of trees on farms also contributes to environmental and community benefits so is expected to occur over the next few years.

[39] https://www.mpi.govt.nz/forestry/forest-industry-and-workforce/forestry-and-wood-processing-industry-transformation-plan/

8.3.1 Forest owners

Large corporate forest owners account for 71% of the planted forests (106,824 ha). These owners tend to have long-term forest management contracts and aim to harvest at sustained levels. Small owners account for the remainder 29% (43,881 ha), with only a few of them engaged in long-term contracts.

8.3.2 Wood processors

Log and timber processors in Northland process approximately 1.1M tons of log in mixed grades and sizes every year, mostly creating products for the domestic market, using logs purchased from the forest companies. These products include building and farming products. The main residues from wood processors are sawdust,[40] bark,[41] woodchip,[42] shavings,[43] dockings[44] and post peeling.[45]

Timaru, Canterbury, New Zealand. Credit – Chris Stanley.

[40] Sawdust is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.

[41] Bark is created when preparing the log for processing and the volumes are generally small as most of the bark is removed in-forest.

[42] Woodchip is created onsite from all viable offcuts and is sold for landscaping, animal bedding or to MDF.

[43] Shavings are created when dressing the timber, which creates a finished product smooth and clean. Shavings are usually created after the timber has been dried so it is light and dry and is good boiler fuel.

[44] Cutoffs from docking the timber to specified lengths. It is used as firewood.

[45] Post peeling are the residues created from round posts (fencing poles, lamp post). They are thin and long in shape, making them difficult to handle. Additional processing may be necessary to create a more uniform product for bioenergy.

8.4 Assessment of wood availability

This section considers:

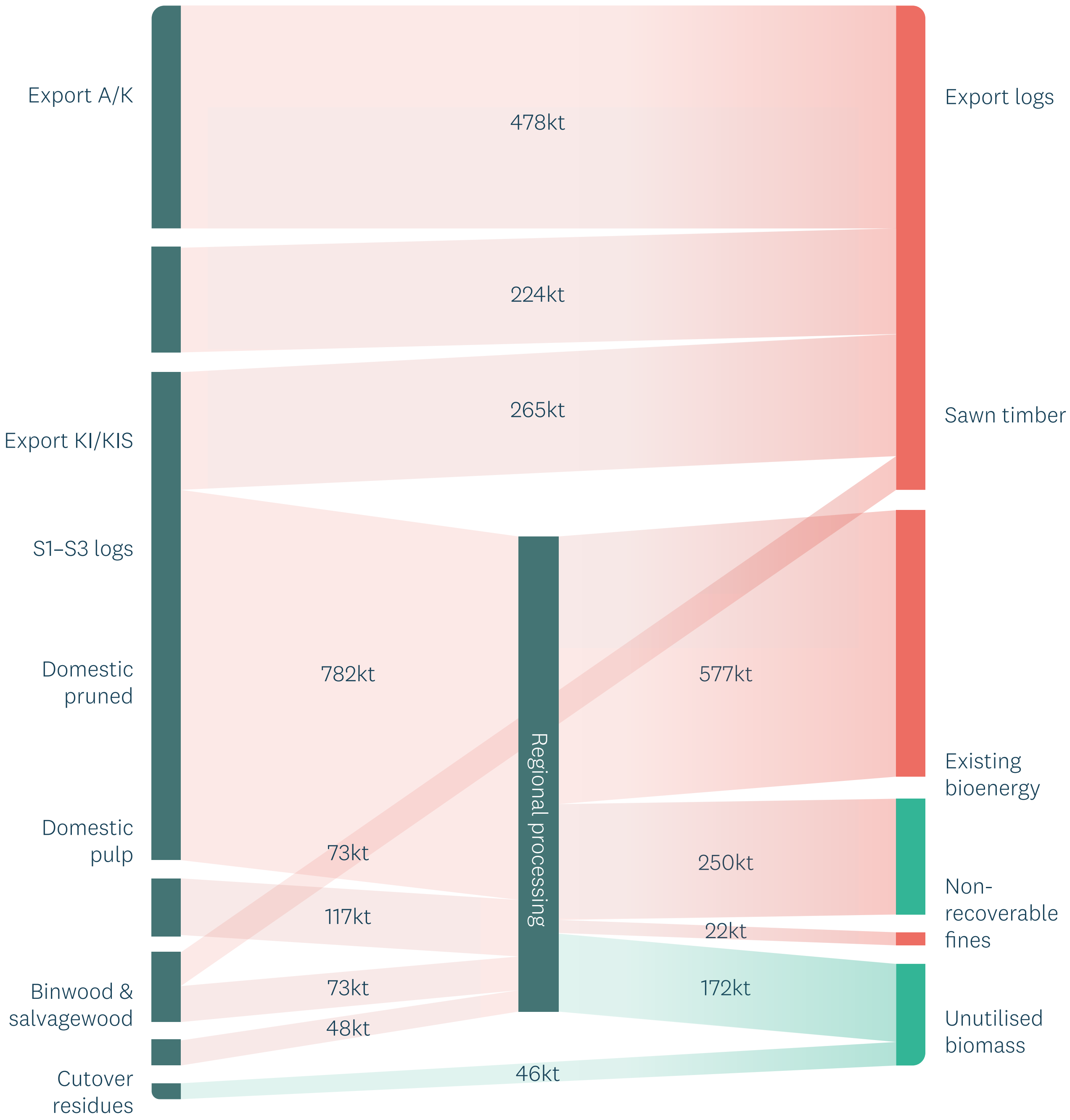
- The total wood, and the grades of wood, expected to be harvested in the region over the next 15 years.
- What are the existing markets for that wood, including the role of any processors in the region, and existing bioenergy uses.
- How much of that wood (including harvesting and processor residues) are currently unutilised.

The outcome of this section is summarised in Figure 40. Wood flows that could be utilised for new bioenergy demand from process heat are shown in green.

We note that the numbers in this figure are averages over the 15-year period from 2023 to 2037. We use this period to highlight the near-term availability. Later in this section, Figure 36 illustrates this changing availability in more detail, and over a longer period.

Port Blakely, Canterbury, New Zealand. Credit – Chris Stanley.

Figure 32 – Wood flows in the Northland region. Source: Ahikā, Margules Groome



A top-down analysis suggests that an average of around **2,105,000 pa (15,119TJ) of wood will be harvested in the Northland region over the next 15 years** although volumes are significantly higher than this over the period 2023-2026. A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses reveals:

- On average, **94,178 pa (676TJ) of harvest residues could be available for bioenergy.** Around 47,827 pa (343TJ) is currently being recovered and is destined for processors[46], while the rest is not currently utilised.
- Interviews with sawmills suggested that around 421,800t **pa (3,030TJ) of processing residues** are produced (mostly post peelings) of which 249,700t pa (1,794TJ) is currently being used for bioenergy (mostly woodchip).
- On average over 15 years, **368,900t (2,649TJ) of domestic pulp/firewood and export KI/KIS logs is available.**

Overall, EECA estimates that, on average over the next 15 years, **approximately 218,500t per year (1,569TJ) of woody biomass is currently unutilised and could be recovered for new boiler demands without disrupting low grade export markets or existing bioenergy consumers.** However, this average disguises the significant variance in the annual availability shown in the analysis below.

8.4.1 Forecast of wood availability

For this report, a recent mapping of the forests in the catchment (Taitokerau)[47] has been undertaken to assess distribution of crop types and ages. This has been complemented with log-grade data provided by forest owners. The wood availability forecast below is based on this more recent mapping of the catchment.

In Figure 33 total volumes are broken down into log grades using national exotic forest description (NEFD) data and the log-grade split for Northland forest owners as provided for MPI's Wood Availability forecast (WAF).

Key log grades are:

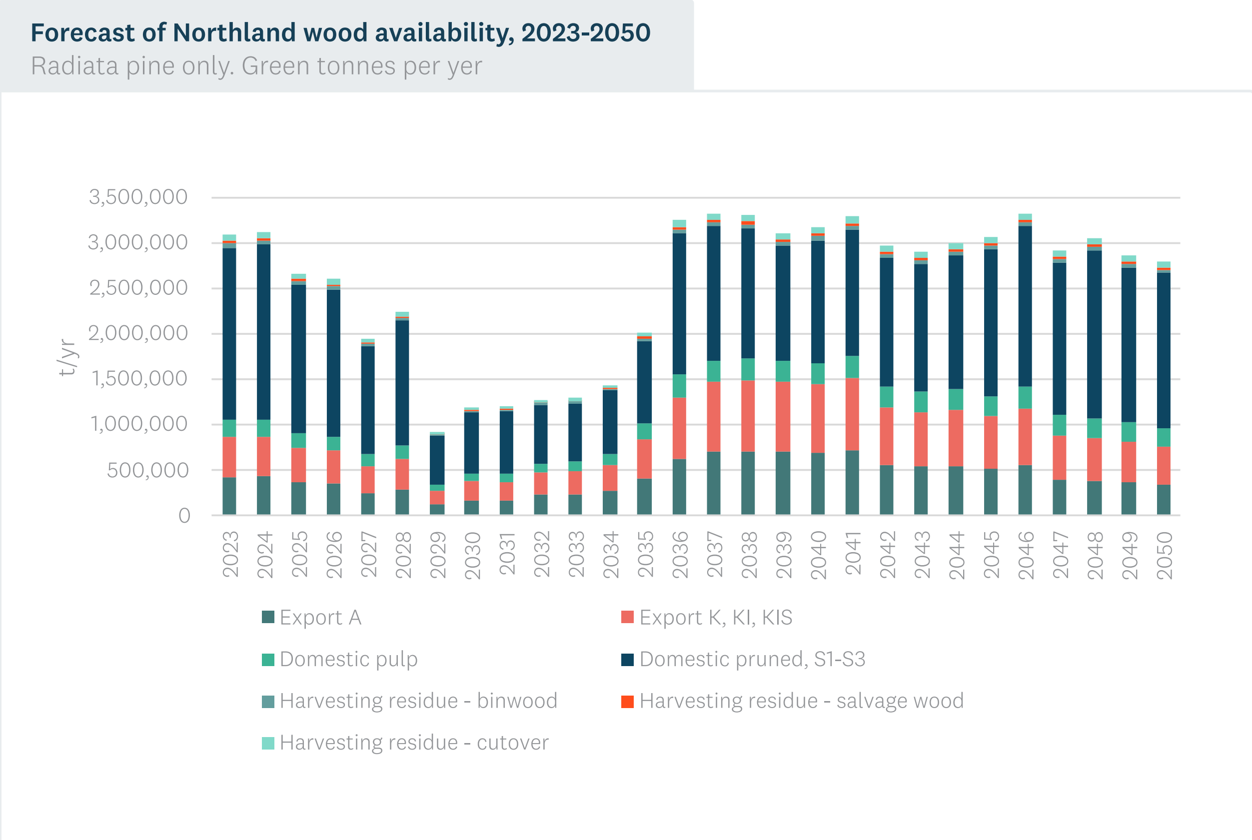
- **Export grade** – This includes A, K, KI and KIS grades logs exported to Asia.
- **Domestic grade** – This includes Pruned, Unpruned, and Pulp log grades. These grades go to domestic markets including wood processors and firewood.
- **Harvesting residues** – A by-product of harvesting and a primary source for bioenergy and firewood. It is commonly referred to as 'billet' wood; here it is split into 'binwood' (biomass that is easily accessible and is collected by truck with a bin), 'salvage wood' (salvageable biomass collected using a log reach excavator) and 'cutover' (residues from stems and branches left in the forest and not as easy to access). Based on surveys of Northland forest owners, residue volumes have been estimated to 15.5% on average out of total available wood (including non-recoverable biomass). This 15.5% is broken down as follows: 1.3% binwood, 0.8% salvage wood, and 13.5% cutover. However, due to the difficulty of accessing cutover residues, only 15% of cutover residues has been determined to be economically recoverable. The costs of recovering residues are discussed further below.

Export grade volumes are sent to Marsden Point. Domestic grades are utilised in Northland by local processors.

46 Binwood is processed with pulp logs and salvage wood to make wood chip for export markets.

47 This review includes the National Exotic Forest Description Territorial Districts in the Northland Wood Supply Region including Far North, Whangarei and Kaipara but excludes Auckland as this is outside the EECA definition for Northland/Taitokerau.

Figure 33 – Forecast of Northland wood availability, tonnes, 2023-2050. Source: Forme



As can be seen from Figure 33, the total available wood resource falls over the period 2026-29 and increases from 2030. This occurs due to the age distribution of the existing forests (around half of Radiata pine is more than 14 years old), combined with the assumptions in the WAF model regarding when forests are harvested.

That said, a model can only predict how wood flows may occur subject to assumptions that drive individual forest harvest. It is important to recognise that forests are normally managed in a way that maximises the benefits to the owners. Such benefits are not easily modelled particularly as prevailing market conditions will change. Each owner has their own harvesting strategy based on the wood flow objectives and forest revenue. Any change in harvesting strategies by forest owners will affect the age structure and maturity of the forests they own and, in turn, future wood availability.

The large-scale owners hold 71% of the modelled resource, and small-scale owners hold the remainder. A key issue is the timing of harvesting by small-scale forest owners. The harvest age can vary markedly even between neighbouring properties. The volumes forecasted by larger forest owners are subject to alteration because of changes in harvesting intentions or changes in the resource description (for example, areas and yields). But a higher level of confidence can generally be assumed for these owners than for small-scale owners, whose harvest intentions are less clear due to being more reactive, and with less accurate resource descriptions.

8.5 Insights from interviews with forest owners and processors

The results of the WAF modelled was complemented with a set of detailed interviews and surveys of the major forest owners and processors. This provides a richer picture of the potential resource available for bioenergy.

8.5.1 Processing residues

Sixteen processors in the region were interviewed to better understand both the potential residues from processing, as well as the current demand for these residues for bioenergy.

Table 8 shows the types[48] of processing residues readily available from Northland processors.

Table 8 – Products readily available for bioenergy from processors in Northland

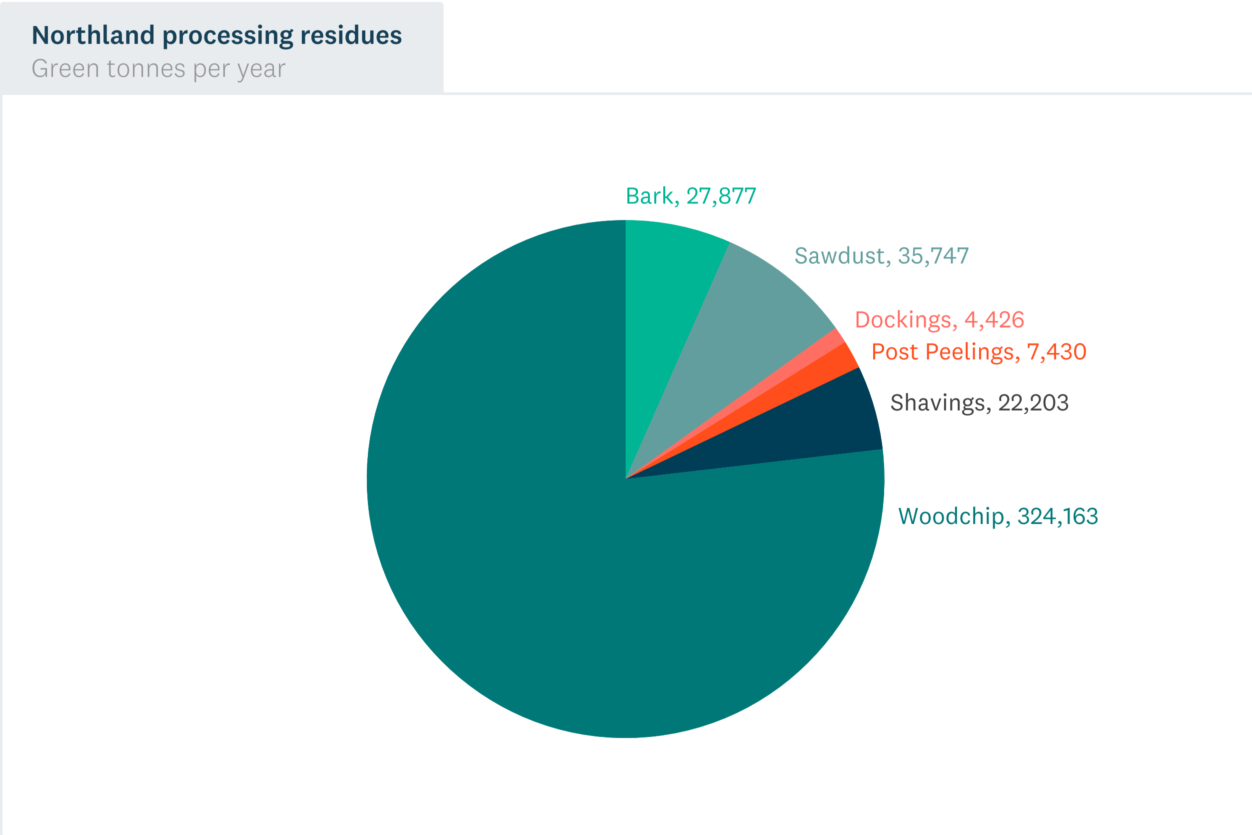
	Woodchip	Sawdust	Bark	Shavings	Post peelings	Dockings
Hermpac - Ruakaka				x		x
Northsawn Lumber - Ruakaka				x		x
Waipapa Pine	x	x	x	x		
Croft Sawmill	x	x	x	x		x
Northsawn Lumber - Moerewa	x	x	x	x		x
Kaihu Valley Sawmill	x	x	x	x		x
Mt Pokaka	x	x	x	x		x
NorthPine	x	x	x	x		x
Rosvall Sawmill	x	x	x	x		x
Topuni Timber (Scragg)	x	x	x			
CHH Futurebuild LVL	x		x			
Juken NZ Ltd - Triboard	x	x	x			
Juken NZ Ltd - Veneer	x	x	x			
Croft Timber	x	x	x		x	
Topuni Timbers	x	x	x		x	
Marusumi	x		x			

48 Definitions of the different types of residues can be found in Appendix D.

The interviews conducted suggest that there are, on average, 421,845t per year of processing residues created in Northland, the majority of which is woodchip (Figure 34). Small volumes of this woodchip is currently being sold to a pulp mill in the Central North Island, and is used to improve the average density of pulp furnish used in fibrocement products.

Each year, 249,724t of processor residues are already being utilised by Northland processors for their own bioenergy needs, mainly woodchip and small quantities of sawdust and shavings.

Figure 34 – Northland processing residues, tonnes per year (15-year average). Source: Ahikā interviews



8.5.2 In-forest recovery of biomass

In forest residue volumes were estimated by Forme. Based on forest owner surveys, Northland's in-forest residues have been split into three categories[49]:

- **Binwood** accounts for an average of 1.3% of total available wood volumes (35,4315t per year on average over the 2023-2050 period). Practically, this will include skid site, roadside and easily accessible residues.
- **Salvage wood** accounts for an average of 0.8% of total available wood volumes (23,021t per year on average over the 2023-2050 period).
- **Cutover** accounts for an average of 13.2% of total available wood volumes (377,651t per year on average over the 2023-2050 period).

Based on interviews with forest owners all binwood and salvage wood is currently being recovered and are mainly used by the Marasumi processor (alongside pulp logs) to make woodchip for export.

No cutover residues are currently being recovered. The issues faced with in-forest residue recovery include:

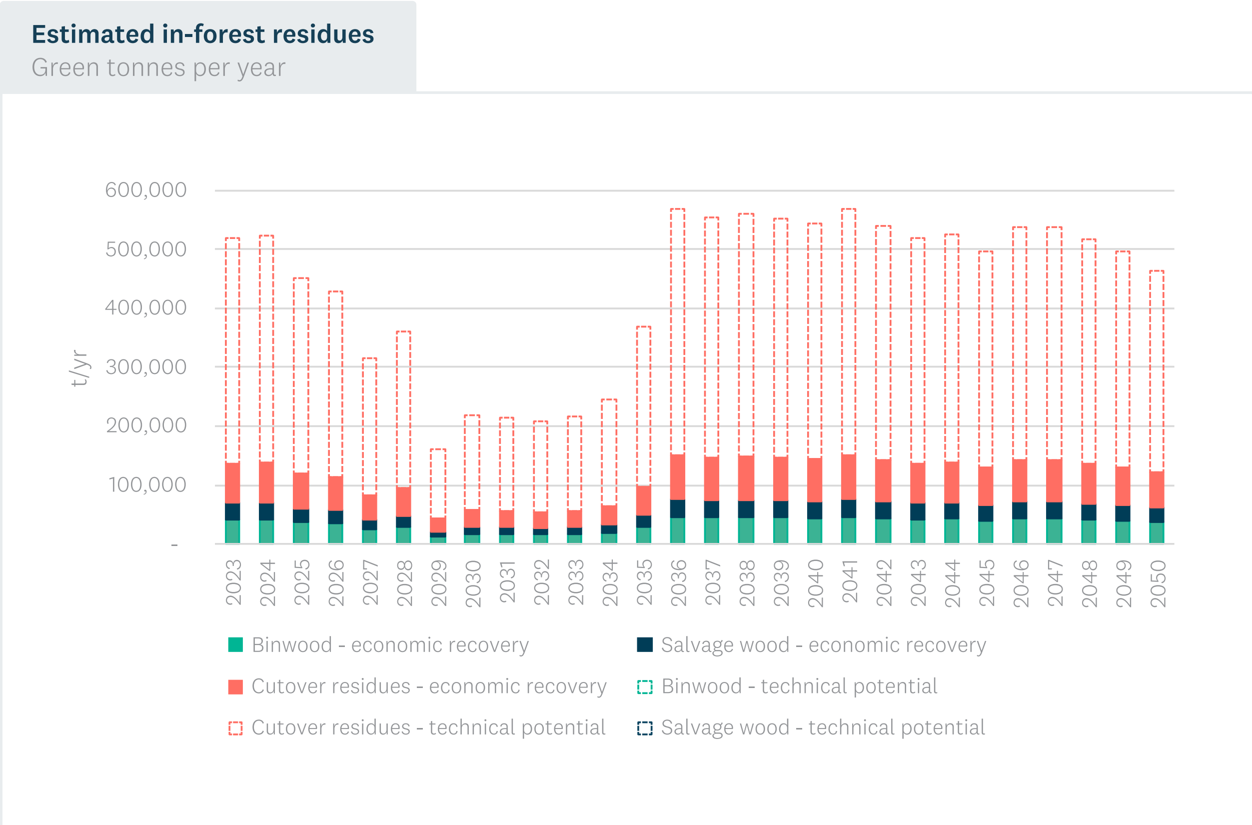
- Land accessibility can be difficult due to steep terrain, which also makes recovery of cutover residues more difficult and costly to extract. As the proportion of steep terrain increases, the overall practical level of residue recovery drops.
- Commentary from foresters suggests that even some of the roadside volumes gets left behind because the market price would not exceed to cost of collection and distribution.

A more definitive estimate of cutover recovery resources and cost requires an assessment of the underlying terrain, as recovery on steep hauler country is likely to be substantially lower than on ground-based country. This information was not available for Northland RETA. We have scaled back assumed recovery of harvesting residues from the theoretical potential (shown in Figure 33), using expert opinion.[50] This applied more pragmatic recovery factors for different volumes, based on assumed methods of recovery (ground-based and hauler-based), and resulted in a reduction of cutover volumes by 85% respectively. Realistic harvesting residue estimates average 115,099t per annum over the next 15 years, albeit with higher volumes initially and lower volumes later (see Figure 35).

49 See definitions in Appendix D.

50 Forme, 2023.

Figure 35 – Estimated in-forest residues, technical potential vs economic recovery. Source: Forme, EECA



The final assessment only uses the pragmatic estimate of recovery volumes.

8.5.3 Existing bioenergy demand

The interviews highlighted where some of the sources of potential biomass are already being used for bioenergy:

- A large proportion of processing residues (woodchip, sawdust, and bark) are being used internally by wood processors as boiler fuel, totalling 249,724 tonnes.

In the analysis below, we assume that these bioenergy demands continue into the foreseeable future.

8.6 Summary of availability and existing bioenergy demand

Figure 36 below shows our overall assessment of the forest (and forestry by-product) resources in Northland.

Figure 36 – Wood resource availability in the Northland region WAF and additional analysis. Source: Forme, EECA

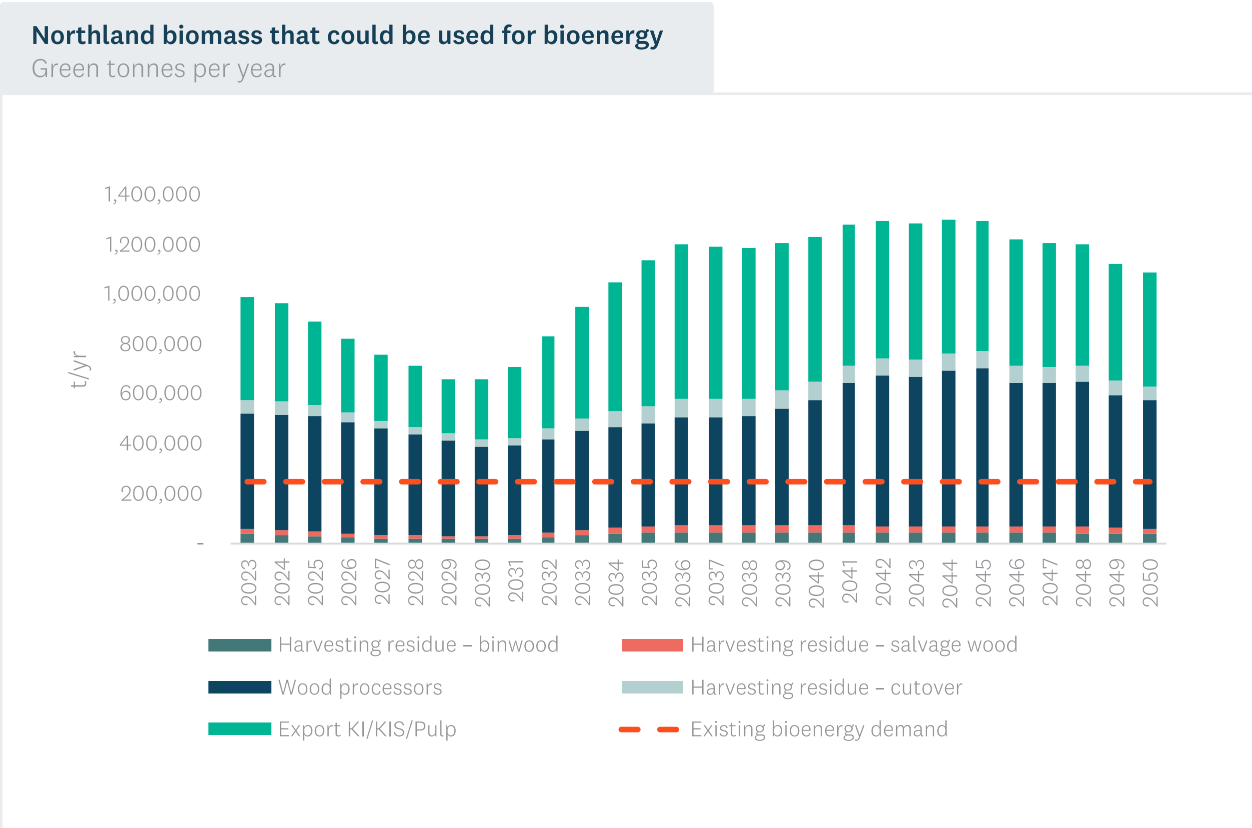


Figure 36 shows there is significant scope to increase the use of bioenergy from the level today (~249,724t, or 1,794TJ). We note that domestic pulp (for firewood or MDF production) is excluded from the availability assessment on the basis that the potential consumption of woody biomass for bioenergy should not disrupt domestic markets for timber. Export A-grade and K-grade timber are also excluded due to cost (see below).

We now turn our attention to the likely cost of the potential bioenergy resources identified above.

8.7 Cost assessment of bioenergy

Since bioenergy markets are very much in their infancy, the approach is to base prices on either an estimate of the costs of extracting the resource, or to 'shadow price' the value of resources in other markets (where these markets existed). For example, shadow pricing uses export prices for wood, to imply a price that must be 'matched or beaten' if users are to divert their wood resources away from that market to bioenergy.

8.7.1 Cost components

A key cost component is the cost of transporting the material from source to a hypothetical processing location, which for the Northland Region has been assumed to be Ngāwhā.[51] Depending on the source, prices have been determined as follows:

- **Wood processing residues** – The price for the wood processing residues is the sum of the cost of the material at the processing mill plus the cost of transporting it to the hub. It is assumed that the material is already in a form that could be consumed for energy production, hence only storage, handling, and hub margin costs are added.
- **In-forest binwood, salvage wood and cutover volume** – A forest owner's costs (collection, loading, transport from forest to biomass hub) are added to the biomass hub costs of chipping, storage, and handling.
- **Diverted export volume** – All the export volume from Northland is assumed to be transported to Marsden Point at present. The difference between the transport cost to Marsden Point and to the biomass hub is subtracted from the at-wharf gate export price. The biomass hub costs of chipping, storage and handling the biomass is then added to the price.

Waewaetorea Passage and Island in the Bay of Islands. Credit – Northland NZ

[51] Another potential site for the hub could be Marsden Point.

8.7.1.1 Estimated costs of bioenergy

Table 9 and Figure 37 show these costs in terms of mass and (in $/t biomass) and energy equivalent ($/GJ). This requires an assumption about the moisture content of the underlying fuel. We use calorific value associated with a moisture content of 55%; in reality, the moisture content will vary between the different sources listed in Table 9; this will need more detailed consideration by process heat users contemplating conversion to biomass.

Table 9 – Sources and costs of biomass resources in the Northland region. Source: Forme (2023)

Bioenergy source	Cost of biomass source ($/t)	Harvesting and collection ($/t)	Chipping and storage ($/t)	Transport to process heat user ($/t)[52 53]	Total cost delivered to user's site ($/t)	Total cost delivered to user's site ($/GJ)[54]
Processor residues – woodchip	$56.25	$0	$10	$25.02	**$91.27**	**$12.71**
Processor residues – excl woodchip	$9.12	$0	$10	$25.02	**$44.14**	**$6.15**
Harvesting residues – binwood	$30.3	[included]	$25	$28.87	**$84.15**	**$11.72**
Harvesting residues – salvage wood	$2.1[55]	$12.5	$25	$28.87	**$68.51**	**$9.54**
Harvesting residues – cutover	$2.1[56]	$25.04	$25	$43.3	**$95.49**	**$13.3**
Pulp	$59.8		$25	$25.02	**$109.84**	**$15.3**
Export grade KIS logs	$61.7	[included]	$25	$25.02	**$111.73**	**$15.56**
Export grade KI logs	$72.2			$25.02	**$122.18**	**$17.02**
Export grade K logs	$83.8	[included]	$25	$25.02	**$133.82**	**$18.64**
Export grade A logs	$97.8	[included]	$25	$25.02	**$147.79**	**$20.58**

The figures in the far-right column of Table 9 only include the cost of primary transport from the forest to a hub that is assumed to be at Ngāwhā.[57]

52 Also note that for volumes diverted from export, a reduction in transport costs is warranted, as these are currently transported to Ngāwhā for export, and this component is saved if they are used locally.

53 We note that on annual basis, the transport cost varies depending on the location of the forest.

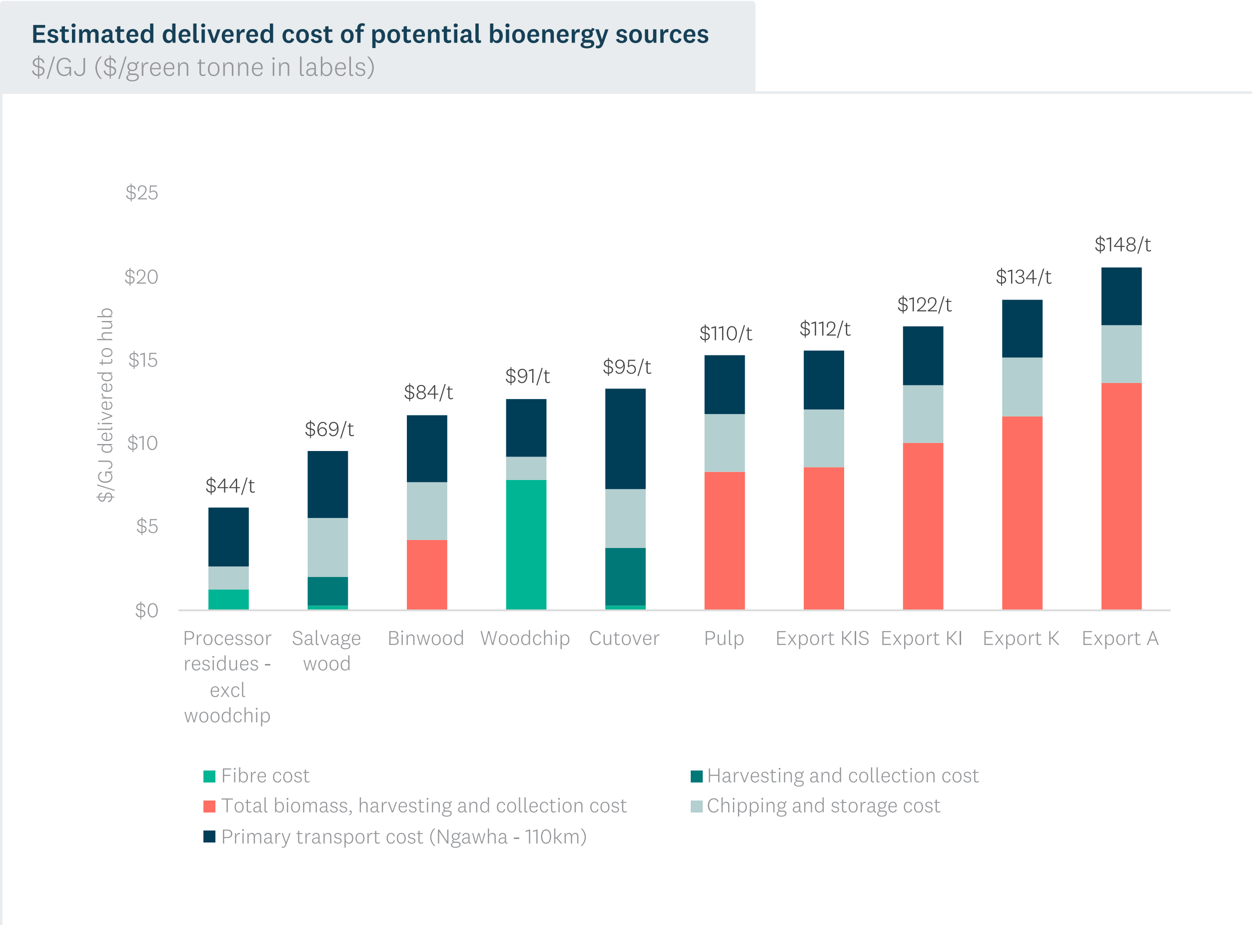
54 Conversion in energy equivalent assumes a net calorific value of 7.184 MJ/kg (55% moisture content), and 1m3 = 1,000kg. We also note that this is a price of energy as delivered to the gate and is therefore not directly comparable to an electricity price, due to the relatively lower biomass boiler efficiency compared to an electrode boiler (or a high temperature heat pump, where applicable). We expand on this comparison in Section 8.

55 We note that this is current fibre cost as determined through interviews in the area. Costs are likely to increase once a market for harvest residues is established.

56 As above.

57 'Secondary' transport from the Ngāwhā hub to the process heat user are used in the MAC calculations, assuming $18/t ($2.50/GJ) over a distance of 60km from the hub.

Figure 37 – Estimated delivered cost of potential bioenergy sources. Source: Forme (2023)



We reinforce that we retain export grades A and K logs in the analysis not because we believe these are sustainable or practical sources of bioenergy. Rather we use them in the supply curve to represent 'scarcity values' if our scenario analysis below should indicate that other more plausible and sustainable sources of bioenergy are insufficient.

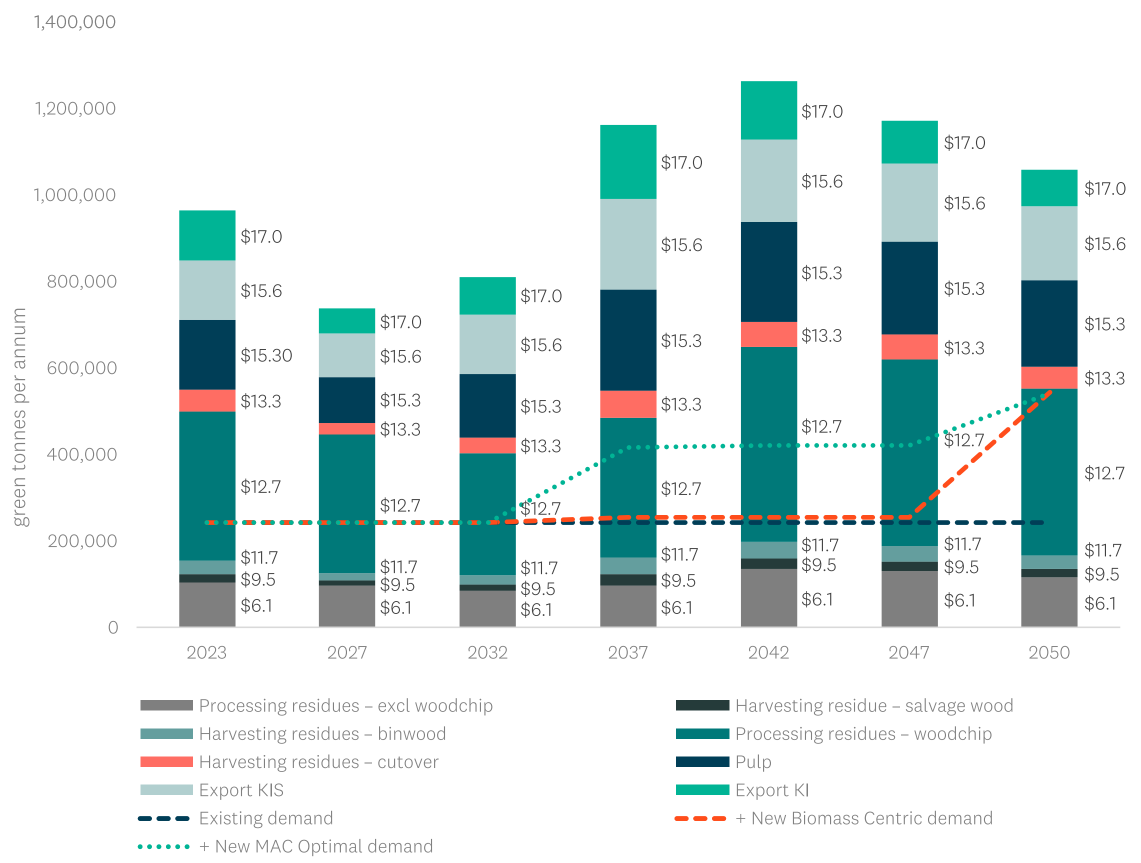
8.7.2 Supply curves

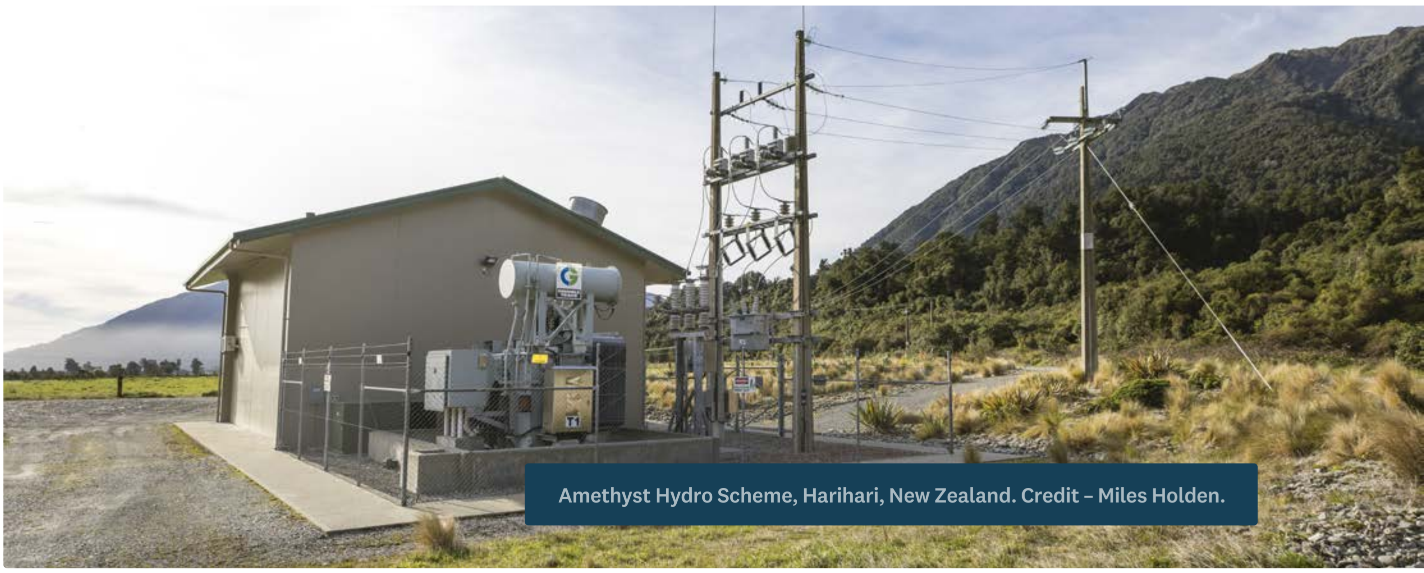
To convert these costs into an indicative market supply curve, we use the corresponding volumes for each category of resource from the analysis in Section 8.6 above. Since the supply of near-term bioenergy resource availability varies through time, we produce three supply curves (in addition to current), one for each of the five-year periods through to 2050 – this is shown in Figure 47 below, which overlays demand pathways on supply costs.

Figure 38 provides a summary of available biomass volumes and the total delivered cost of each type of biomass. Note that the costs shown here do not include secondary transport costs from the processing hub to the final user, they only include transport costs from the forest to the Ngāwhā hub. We also note that the cost of harvesting residues may change through time once a market is established for this type of biomass.

Figure 38 – Biomass supply curves through to 2050. Source: Forme (2023)

Northland biomass delivered costs
$/GJ





Amethyst Hydro Scheme, Harihari, New Zealand. Credit – Miles Holden.

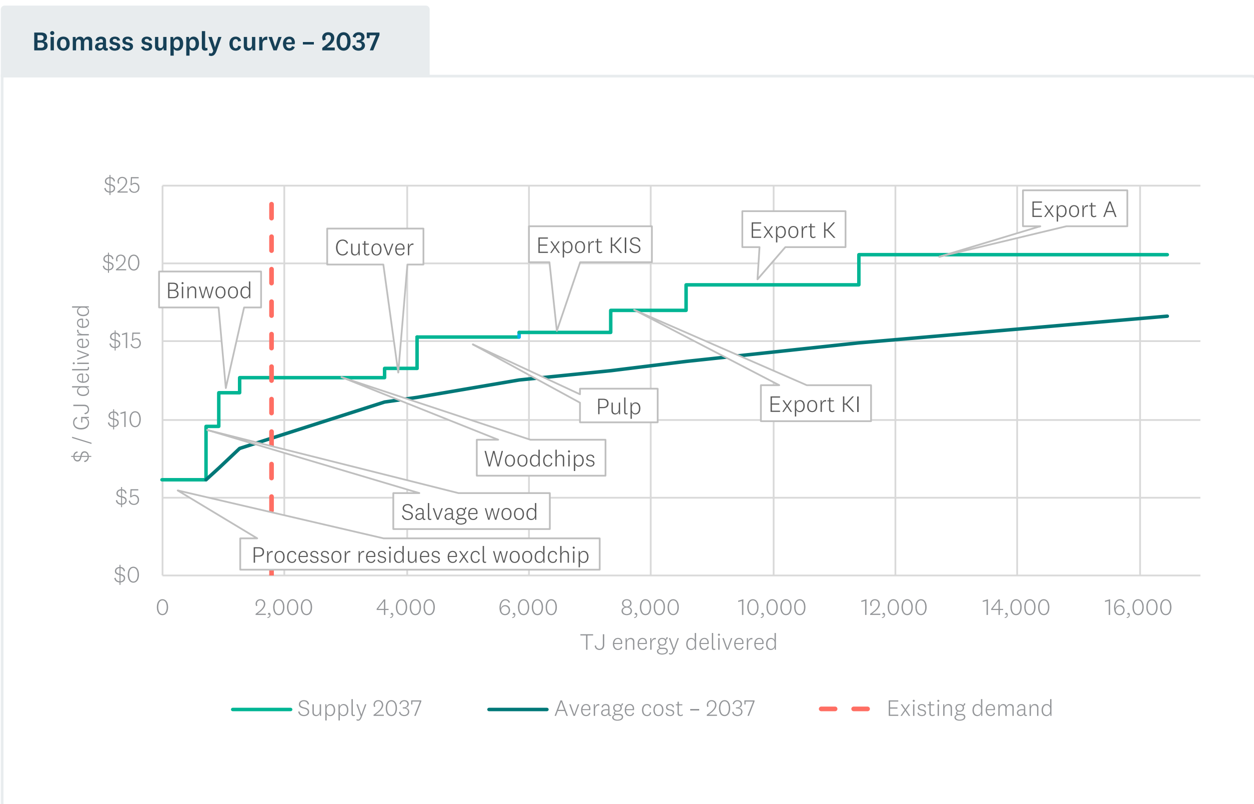
To illustrate, Figure 39 shows the biomass supply curve and average prices for 2037.

The supply curves have three dimensions: volume, cost, and time. The cost shown by the solid line for each increment in supply is the marginal cost for the most expensive resource required to meet that level of demand. This is higher than the (volume-weighted) average cost paid by the market overall at any point in time (which would include the lower cost resources). It allows us to think about the price bioenergy users may face in any year in two ways:

- If early biomass customers secure long-term contracts for lower cost processor residues or in-forest residues (indicated by the dashed lines), they will still have access to those resources, at the agreed price, for the duration of those contracts. This is regardless of what is happening in the rest of the market. As each subsequent process heat user switches fuels, they will contract for the lowest cost resource that has not already been secured by an earlier adopter. Hence the supply curves in Figure 44 indicate the price faced by the next increment of demand, assuming that all cheaper biomass resources have been fully contracted, at least for the remaining period of the chart.
- Alternatively, the biomass market may operate on a ‘spot’ basis, without any long-term contracting. Every year, aggregators of bioenergy resources suitable for process heat will secure the supply, and all users will pay a price approximating the average cost across all the resources.

Reality will likely lie somewhere between these two scenarios, depending on how the arrangements for long-term supply of bioenergy evolve.

Figure 39 – Biomass supply curve, 2037. Source: EECA



8.7.3 Scenarios of biomass costs to process heat users

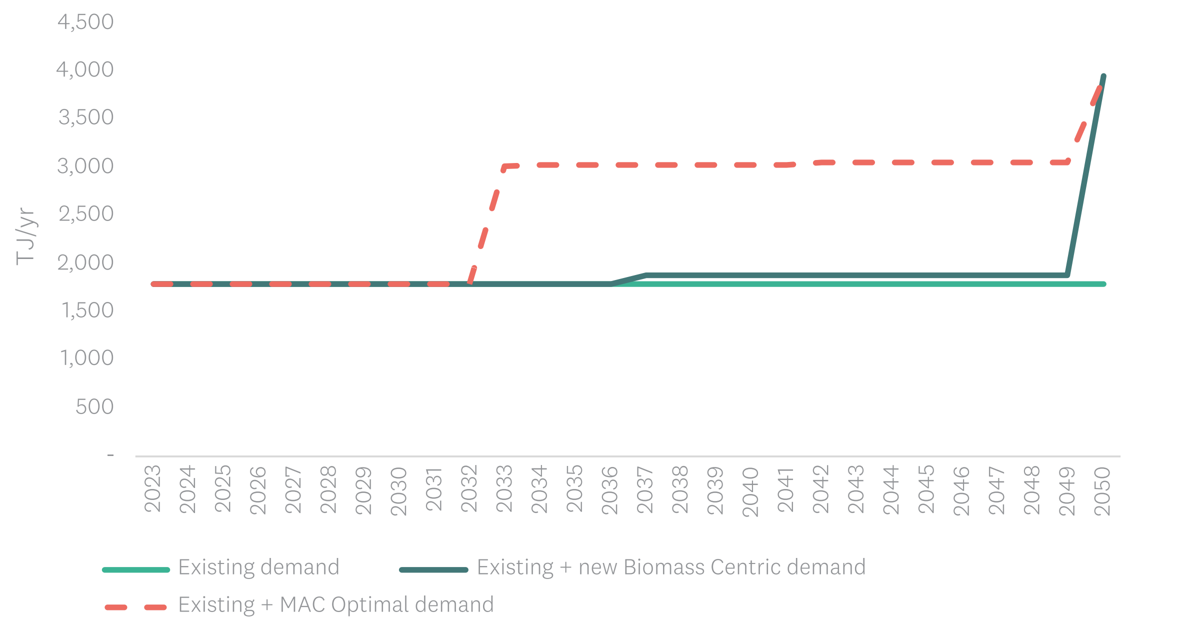
With a nascent bioenergy market, there is no price history to draw on to use to calibrate price forecasts. To get an indication of what prices may be, we overlay plausible demand scenarios on each of the three supply curves above. Recall that these supply curves are based on a forecast of the costs of accessing these resources in 2023, with no additional margin applied, which is only intended to provide a proxy for potential future price scenarios.

These demand scenarios include the present consumption of bioenergy (~249,724 per year) and assumes this continues throughout the 2023-2050 period.

Our demand curves through time (Figure 40) illustrate a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study[58], i.e. it is a conservative forecast of biomass demand. The timing of each conversion (and hence when each increment will arise) is set by the dates in each organisation's ETA pathway, or, in the case where no date is set, 2050.

Figure 40 – Pathways of Northland region bioenergy demand for process heat to 2050. Source: EECA

Northland region potential process heat biomass demand
Pathways: BAU Biomass Centric and MAC Optimal



[58] Note committed switches to electricity are excluded.

Below we overlay the various increments in demand on the three supply curve periods.

Figure 41 – Biomass supply and demand in 2027, 2032, 2037, 2042, 2047 and 2050. Source: Forme, EECA

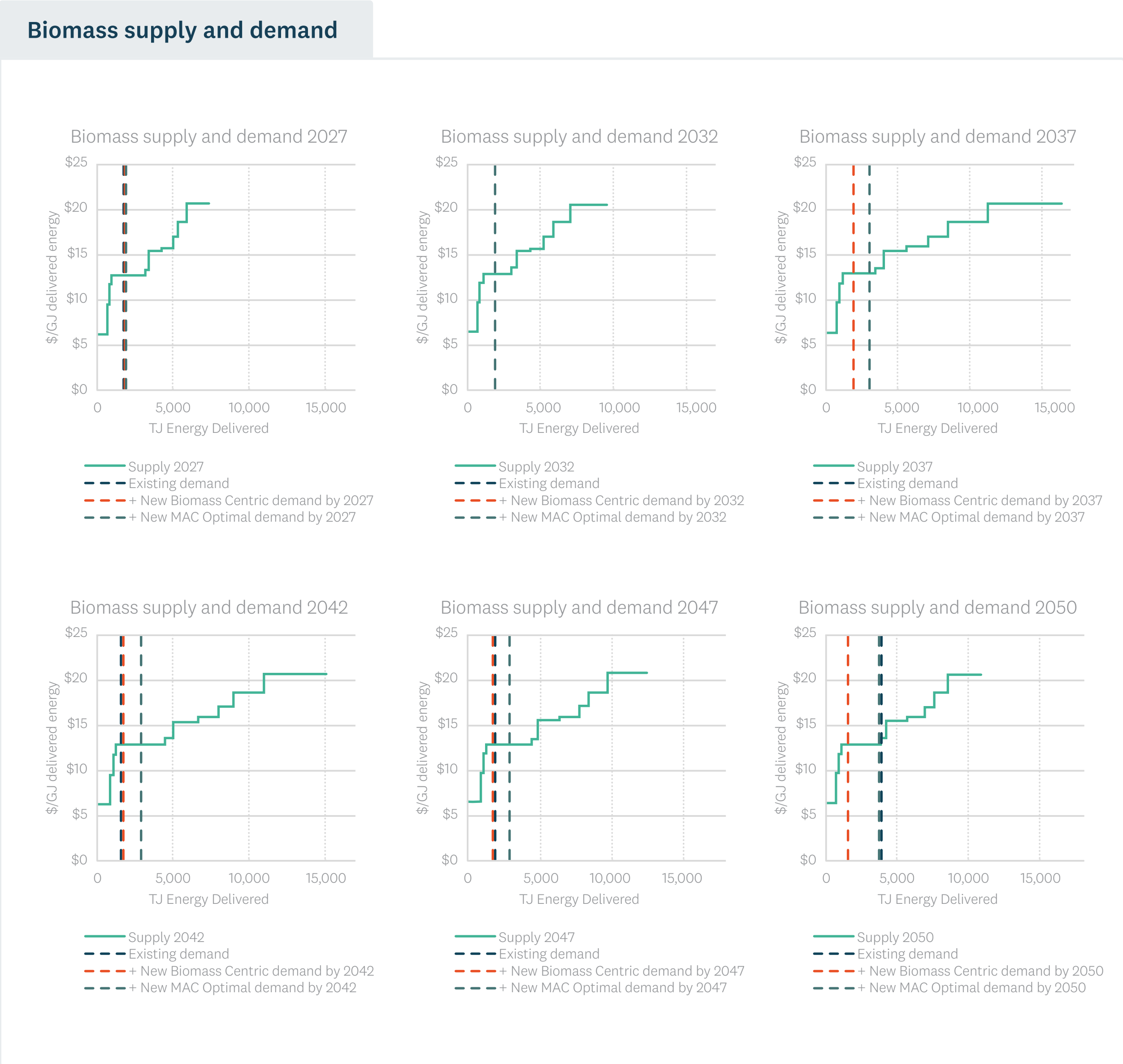


Figure 41 illustrates that in 2027 and 2032 there is no increase in demand over and above existing demand. In 2037, the MAC Optimal pathway (3,036 TJ, including existing demand) sees an increase of 69% in the use of biomass compared to existing demand, using all salvage wood and binwood, and 75% of woodchip. By 2050, demand in the MAC Optimal pathway (3,931 TJ, including existing demand) is 119% higher than current demand; at this point, the pathway is using all salvage wood and binwood and 93% of woodchip. Demand in the Biomass Centric pathway does not materially differ from existing demand until after 2047, so that by 2050 it is slightly higher than that in the MAC Optimal pathway (3,957 TJ, including existing demand).

The figure also illustrates that the biomass price is set by the woodchip resource in all years. This price is estimated to be $12.71/GJ, noting that in 2050, the almost depletion of the woodchip resource means that the cutover resource could set the market price, which is estimated to be slightly higher at $13.3/GJ.

9 Northland electricity supply and infrastructure

This section considers the impact of the electrification of process heat on the electricity system.

The availability of electricity generation to meet the demand from process heat users is largely determined at a national 'wholesale' level, from a network of power stations around the country. This supply is transported to an individual RETA site through electricity networks – a transmission 'state highway' grid owned by Transpower, and a distribution 'local roads' network, owned by Electricity Distribution Businesses (EDBs), that connects individual consumers to the boundary of Transpower's grid. The points on the grid where EDBs networks (and potentially some large consumers, such as Fonterra) interface with Transpower's grid are often referred to as 'Grid Exit Points', or GXPs.

Unlike biomass, where markets for the supply and delivery of wood for bioenergy are only starting to emerge, the electricity industry evolved a market and set of institutional arrangements in the 1990s to govern how competing supply resources meet energy demand. These arrangements and rules have led to a range of market participants who compete to provide generation, and compete to provide a variety of commercial arrangements for the supply of electricity to consumers. These institutional arrangements include a framework embedded in legislation that governs the activities of monopoly transmission and distribution networks. Overall, these arrangements strongly influence (and often constrain) how prices are calculated, revenue earned, and assets that are invested in (including timing).

Electrification of process heat often leads to significant increases in demands on local electricity networks. Networks are primarily concerned with any increase in the highest level of instantaneous electricity demand – known as 'peak demand'. This is what EDBs design their networks to cope with.

The wholesale electricity market is designed to ensure that supply of electricity matches the demand for electricity at every instant. The market is designed to incentivise owners of generation to invest in new power stations when demand increases – for example, as a result of the electrification of process heat. If the electricity transmission network is relatively unconstrained, this generation investment can occur anywhere in the country, and be delivered to the new sources of demand.

While the national wholesale electricity market will invariably ensure there is enough supply to meet demand at every point in time (at a price), transmission of power can be a challenge. In some cases, increases in electricity demand will be beyond the existing capability of the local distribution network, and possibly beyond the capacity of Transpower's high-voltage transmission network.

The primary questions for a process heat user considering electrification are:

- What is the price of electricity likely to be, including the costs of wholesale generation, electrical losses, transmission, and distribution[59]?
- Is the existing capacity in Transpower and the EDBs' networks[60] sufficient to transport electricity to their electricity-based process heat location at all points in time?
- If the networks do not have sufficient spare capacity, what is the cost, and ability of network companies' ability to deliver any upgrades required to accommodate the peak electricity demand of process heat users (as well as any other consumers looking to increase electricity demand in that part of the network)?
- To what extent can a process heat user use any inherent flexibility in their consumption in order to reduce the cost of upgrades or electricity?

This section covers these four topics.

Kaikohe Substation, Northland, New Zealand. Credit – Top Energy.

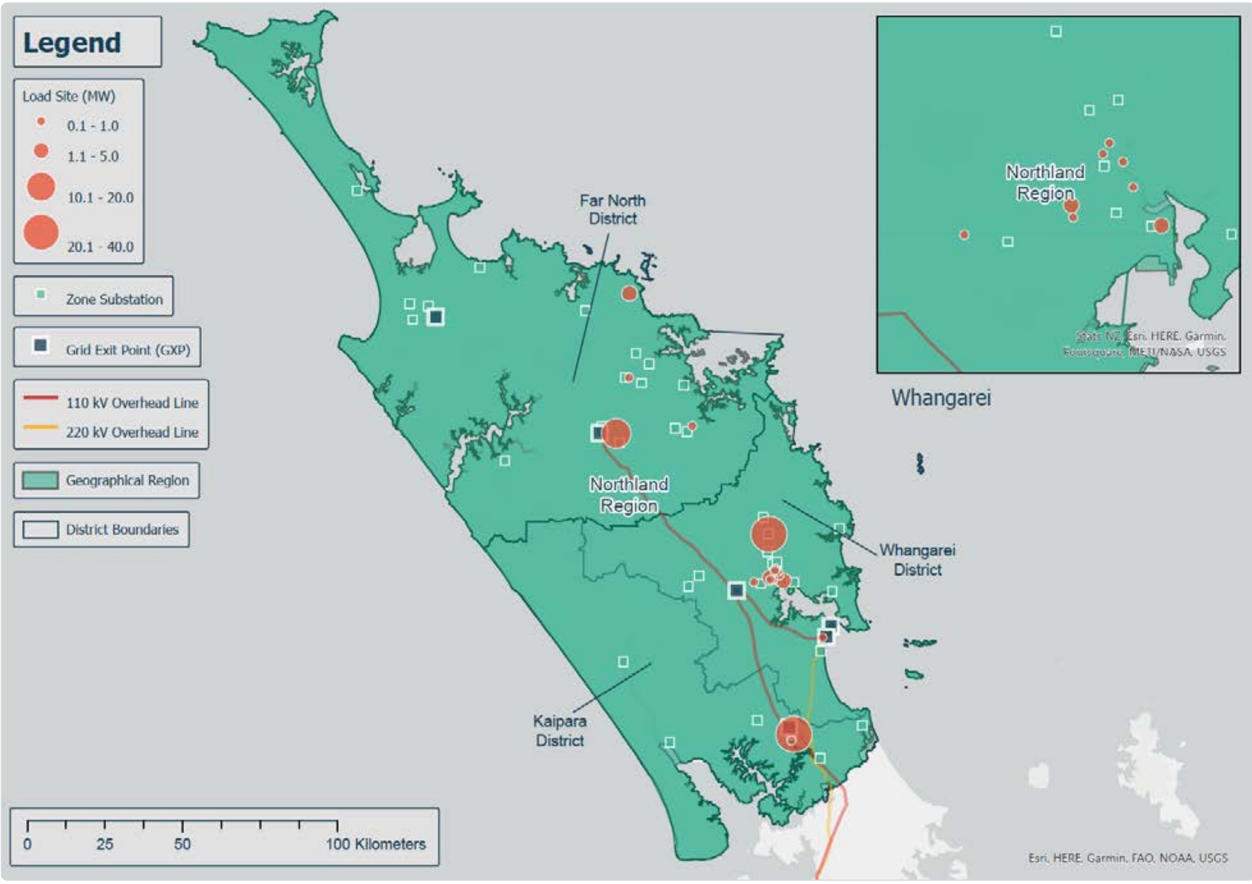
[59] As explained below, this includes metering, regulatory levies and other costs which consumers pay for.

[60] The site's spare capacity also has to be considered, of course.

9.1 Overview of the Northland electricity network

Figure 42 below shows the region's high-voltage grid (owned by Transpower), including the five 'grid exit points' (GXPs) where electricity leaves the national transmission grid and enters the local distribution networks of the EDBs - Top Energy and Northpower. In addition, the sub-transmission substations that are owned and operated by the two EDBs are also shown, alongside the 16 RETA sites considering electrification of process heat (see Table 6). Each RETA site connects to one of these EDB networks.

Figure 42 – Map of the Northland transmission grid, location, and peak demand of RETA sites.



Top Energy supplies a mix of industrial, commercial, and residential loads spread across a network that spans the Far North from northern Hūkerenui to Cape Reinga. Apart from the three main urban centres of Kaitaia, Kerikeri and Kaikohe, much of the region's terrain is rugged and sparsely populated. Northpower is predominantly a mix of residential, commercial, and industrial loads. The latter including wood processing, cement manufacture and milk processing, noting the closure of the Marsden Point Refinery in 2022 significantly reduced the industrial load in the region.

As outlined further below, the geography of the area and the associated characteristics of the assets alongside the types of consumers connected leads to some differences between the two networks.

The Northland region consumed around 1,270GWh of electricity in 2022[61]. Local generation includes Ngāwhā geothermal station (57MW), Wairua hydro station (5MW), and small but increasing amount of solar generation (16MW)[62]. In addition, Northland has several diesel generators, including Manawa's diesel peaking plant (10MW) and 17.2MW of diesel generators dispersed throughout Top Energy's network. The diesel generation sets provide the region with resilience and security of supply during peak periods, and when major supply circuits are out of service.

Together, Ngāwhā and the other local embedded[63] generation (hydro, solar and diesel) produce around 576GWh[64] per year, which represents approximately 45% of the region's annual consumption. This means most of the electricity supply for the Northland region is reliant on energy transported north from Central North Island generation (several hundred kilometres away).

Due to the decommissioning of thermal generation in the Auckland and Waikato regions over the last decade, the Northland region, together with the Auckland and Waikato regions, rely heavily on Transpower's transmission network from the Central North Island. The resultant need to transmit electricity via long transmission lines has the potential to negatively impact the voltage in all three regions under particular operating conditions, such that the voltage moves out of the normal operating range. This issue can be exacerbated when demand is highly variable throughout the day with very low loads overnight, especially in the summer months. To manage this, both Transpower and the EDBs have installed voltage support equipment in their networks.

Electricity use across the upper North Island (which includes Northland) has been rising steadily. With the growing shift toward a lower carbon, more electrified way of life and forecast electrification of process heat and transportation, demand for electricity in the region is expected to increase further. This forecast ongoing increase in demand, alongside the increase in renewable generation being proposed to be connected in the region has identified further potential adverse impacts on the transmission system in terms of ongoing voltage stability issues and thermal constraints under certain operating conditions.

In 2019, Transpower established the Waikato and Upper North Island Voltage Management (WUNIVM) Investigation Project[65] to study the transmission issues in depth and identify potential technical solutions that could be used to address the voltage stability and thermal constraints the region will face over the coming years and into the future.

As part of that work, in 2020 the Commerce Commission approved a major capital expenditure proposal from Transpower which recommended the installation of a mix of voltage support devices and a demand management scheme. The impact of the WUNIVM project on Northland is covered in more detail in section 9.3.3.

61 See emi.ea.govt.nz

62 See emi.ea.govt.nz Installed distributed generation trends.

63 By embedded we mean it is connected to the distribution network, rather than connected directly to Transpower's network.

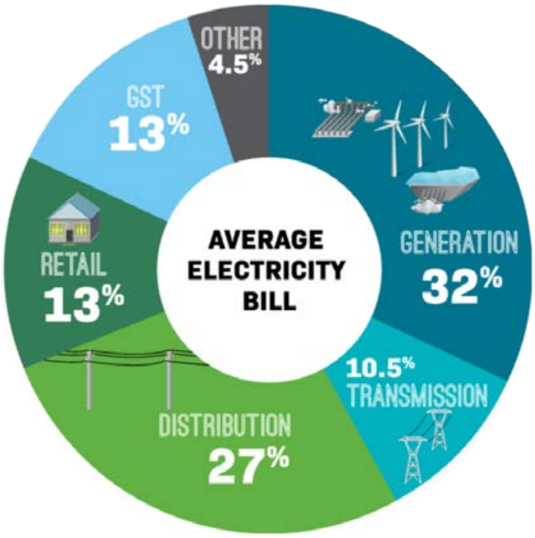
64 Top Energy and Northpower 2023 information disclosure documentation.

65 https://www.transpower.co.nz/projects/waikato-and-upper-north-island-voltage-management-investigation

9.2 Retail electricity prices in Northland

Retail electricity prices, that would be faced by most of the sites[66], reflect the average wholesale cost of electricity plus the network charges levied by EDBs and Transpower for the use of the existing network. The Electricity Authority publishes the image below se howing how the total cost of electricity to a residential household is broken down:

Figure 43 – Components of the bill for a residential consumer. Source: Electricity Authority



However, while all of the components in Figure 43 are also present for large commercial and most industrial consumers, the breakdown will be different, and can vary substantially depending on the size of the facility (in terms of electricity demand), its proximity to a grid exit point, and its location in the country.

In terms of location, the Ministry of Business, Innovation and Employment (MBIE) periodically publish average domestic (i.e. household) electricity prices for 42 locations around the country. This can give us a sense of the cost of electricity in the Northland region relative to other parts of the country, and the role that the major components in Figure 43 play.

66 Again, unless the site connects directly to Transpower's network, in which case it may not use a retailer to interpose between the wholesale market and its purchases. Also, some users may request a 'wholesale' or 'spot' rate from their retailer, where the retailer passes through the half-hourly wholesale price (plus a margin). While this is almost exactly like being a grid connected customer, we consider it a retail arrangement here, due to the potential for margins or re-packaging of network charges by the retailer.

Figure 44 – Quarterly domestic electricity prices in NZ, including GST. Source: MBIE.

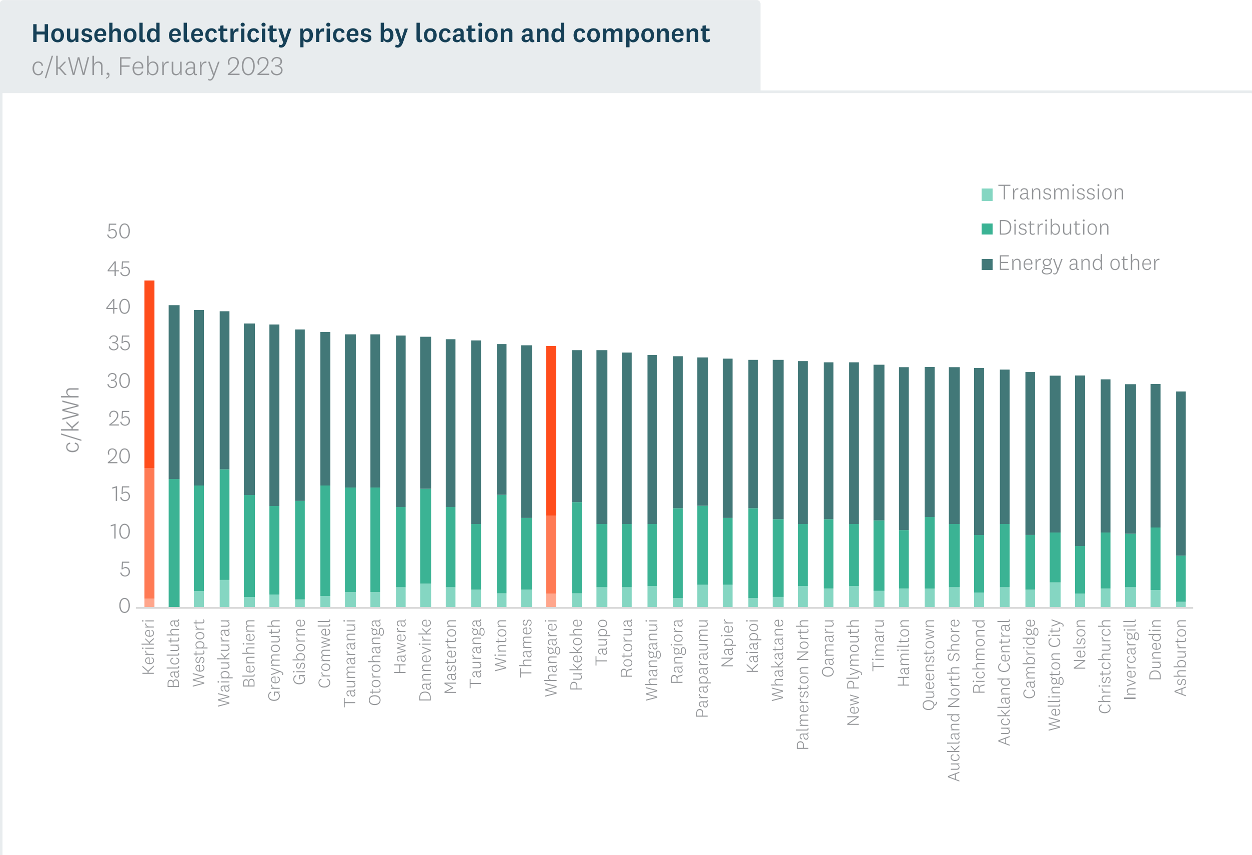


Figure 44 shows that the Northland region has a spectrum of residential prices, ranging from mid-range costs (Whangārei) to the most expensive town (Kerikeri)[67]. These differences are likely driven by the different population densities of the two centres illustrated, as well as the 'long, stringy' nature of the network configuration of the region, in particular the sparse rural network supplying the far north.

These factors will also be present for commercial and industrial electricity consumers, such as potential process heat users considering electric boilers. However, the methodologies that determine the charges paid by commercial and industrial consumers may see these factors manifest differently.

This section provides general guidance on the generation, retail, distribution, and transmission components[68], but it is important that process heat users considering electrification engage with electricity retailers and EDBs to obtain tailored estimates relevant to their project.

67 Note that 'energy and other' in the chart relates to the generation, retail and other components of Figure 49. The high level of transmission losses will be included in the generation component, rather than the transmission component, which reflect the charges for access to the transmission grid.

68 On top of this, process heat sites will also pay charges for metering and Electricity Authority levies ('other' in the chart above).

9.2.1 Generation (or 'wholesale') prices

The generation or 'wholesale' cost of electricity is the result of electricity prices that arise from a market that clears supply and demand every half hour of the year. In order to derive a forecast of future retail electricity prices that can be used to assess the economics of electrification projects, ideally New Zealand needs a model that reflects the likely interaction of supply and demand, and therefore prices, in the wholesale market.

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. Details of EnergyLink's model and simulation approach are discussed in Appendix C. Due to the range in potential future supply and demand outcomes in the electricity industry, and their impact on the wholesale electricity price, three wholesale price scenarios – low price, central and high price scenarios – were included in the EnergyLink modelling.

9.2.2 Retail prices

It should be noted that most large users of power do not elect to face the half hourly varying wholesale price, and instead prefer the stability of multi-year retail contracts, that contain a schedule of fixed prices that each apply to different months, times of week and times of day (generally referred to as 'time of use' contracts)[69].

To reflect the estimated difference between the wholesale price and the retail price that would be faced by consumers, EnergyLink converted their wholesale price scenarios into time-of-use contract price scenarios. This provides a plausible guide (based on historical trends) as to what customers might expect if they were to seek this type of retail contract.

Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options relevant to their operational requirements.

9.2.3 Price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. Three retail price scenarios have been provided, and the detailed assumptions behind these can be found in Appendix C.

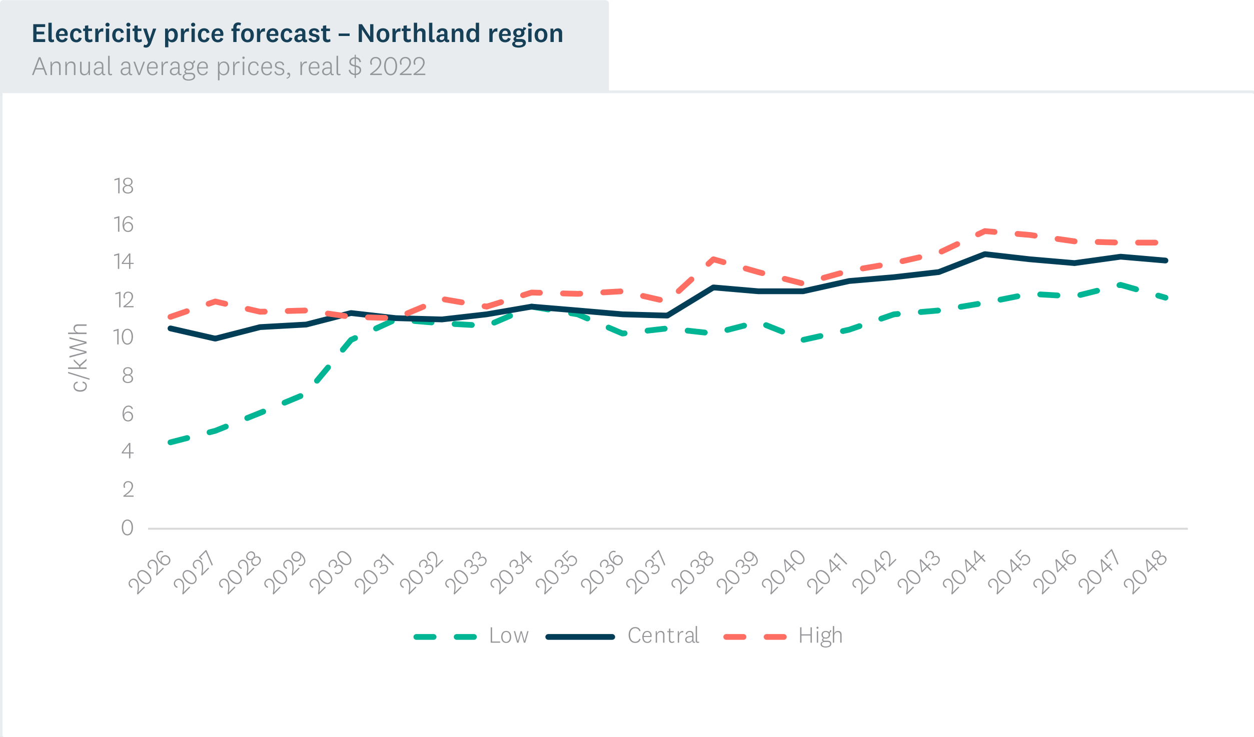
For the Central scenario, real electricity prices increase by 7% between 2026 and 2037 for the Northland region.

As is shown in Figure 45, the impact under the Low scenario (one assumption of which is the exit of the Tiwai aluminium smelter) is significant. While this is a lower end on the range of prices, other forecasts (e.g. Climate Change Commission) show similar impacts from the Tiwai closure, albeit with shorter duration[70].

[69] Common contracts are often referred to as '144 part' contracts, reflecting the fact that the prices are specific to 12 months, two-day types (weekday and other day) and six time periods within the day.

[70] The shorter duration of the price suppression in the CCC's modelling is likely to be due to the fact they did not combine a Tiwai exit with the other price-suppressing variables (e.g. low gas prices, lower decarbonisation demand, lower coal prices) in EnergyLink's modelling.

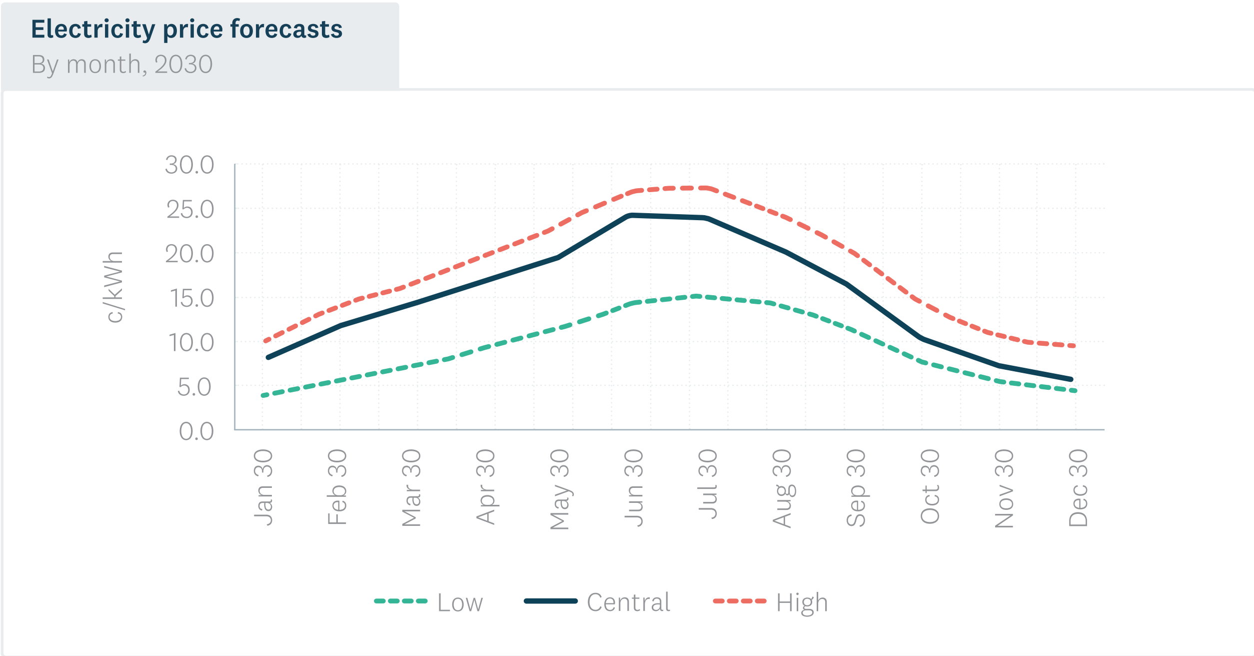
Figure 45 – Forecast of real annual average electricity prices for large commercial and industrial demand in the Northland region. Source: EnergyLink

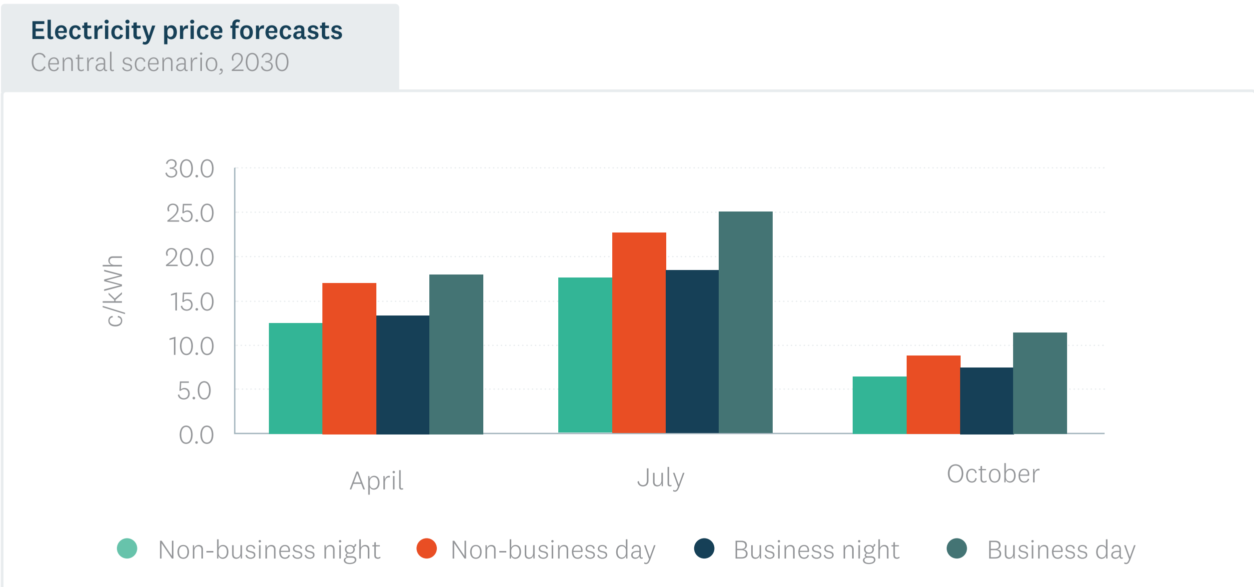


Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond this period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially solar and wind) as technology and scale increases. Other analyses see continued increases. We cannot be definitive about electricity prices 20 years into the future and suggest any business cases consider a range of scenarios.

As outlined earlier, the price forecasts are produced at a finer resolution than the annual average series in Figure 45. Figure 46 zooms in on 2030, showing (a) the variation over the year in the three scenarios, and (b) the variation between day type, and time of day.

Figure 46 – Electricity price forecasts (a) by month and (b) by time block in April, July, and October 2030. Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. The volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 45 above.

As noted above, the prices that a retailer will charge a process heat user will include a network loss factor which is specific to the EDB the customer is located in. EnergyLink's prices do not include this component, but they are incorporated into our modelling in Section 7. Network loss factors are discussed in Appendix C.

9.2.4 Distribution network charges

EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return. The total amount EDBs can earn is regulated by the Commerce Commission, while the way they charge (generally referred to as 'distribution pricing'[71]) is overseen by the Electricity Authority.

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'[72].

Most businesses considering electrification of process heat would likely fall into a 'large customer', 'industrial' or medium voltage (11kV) category of charging for the two EDBs in the Northland region. The five main factors used by these EDBs[73] for pricing in these categories are:

i. Fixed daily charges.
ii. Demand charges (usually related to the highest level of demand reached by the site over a year[74], or the demand level during times when the whole network experiences its highest demand[75], usually measured in kW or MW).
iii. Capacity charges (related to the full capacity of the connection provided by the EDB, measured in kVA or MVA).
iv. Time of use charges, based on kWh consumption during certain, pre-determined times of the day.
v. Power factor charges (based on the power factor of the site), reflecting the need for the network to provide voltage support[76].

These network charges – for both distribution and transmission (refer Section 9.2.5) – are summarised in Table 10 below. The charges in the table do not reflect the exact pricing structures each EDB uses – we have approximated the effect of different variables to simplify the charges for the purposes of summarising into a single price ($ per MVA per annum).

71 By this we mean how they allocate their costs amongst different customer groups, what variables they use to charge customers (e.g. capacity, peak demand, volumetric consumption) and other principle-based oversight. For more information see https://www.ea.govt.nz/projects/all/distribution-pricing/

72 The 2023-24 pricing schedules and methodologies for the two network companies can be found on the websites of Northpower and Top Energy.

73 The two EDBs use different combinations of these factors.

74 Often referred to as 'Anytime Maximum Demand', or AMD.

75 Sometimes referred to as 'Coincident Peak Demand'.

76 In the table below, we did not include power factor charges, on the assumption that the majority of the electrical loads considered in this report would relate to electrode boilers which are understood to be close to unity power factor.

Table 10 – Estimated and normalised network charges for large industrial process heat consumers by EDB, $ per MVA per year

EDB	Distribution charge	Transmission charge	Total charge
Northpower	$90,700	$16,300	$107,000
Top Energy	$150,000	$50,000	$200,000

The difference in prices between EDBs can reflect a variety of characteristics of each network – their pricing methodologies (which determines how costs are allocated between domestic, commercial, and industrial consumers), the nature of their network (e.g. proportion of high-density urban environments versus sparse rural areas) and where they are in their investment cycle.

While we provide these indicative levels of charges for process heat users, it is important that each business considering electrification of process heat engages with their EDB to discuss the exact pricing that would apply to them.

9.2.4.1 Contributions to the capital cost of accommodating new demand

In Section 9.3, we provide estimates of the capital costs that EDBs (and, for some large users, Transpower) would incur in order to upgrade their network to accommodate a particular process heat user's electrification decision.

The charges in that section are presented as total capital costs. Precisely how the process heat user pays for these upgrades, however, is usually more complex than a simple up-front payment. There are a variety of ways that EDBs can recover these costs (assuming that it is the EDB that constructs the new assets[77]). These ways are presented in the EDB's 'capital contribution' policies. These policies recognise the fact that new demand is subject to the cost-recovery charges outlined above, and therefore, over time, a component of the cost of new assets will be recovered through these charges. The EDB may elect to calculate an up-front capital contribution that is only a portion of the total cost of the required upgrades. In some situations, the EDB may design customer-specific charges (often including a fixed component), tailored to the process heat user's expected demand and location in the network.

The exact methodology used to determine the quantum of capital contribution it requires from new electricity demand varies between EDBs. It is important that process heat users contemplating electrification meet with their EDB to discuss how this will work in their situation. For the pathway modelling outlined in Section 7, we assume that EDBs contribute 50% of the capital costs associated with distribution network upgrades required to connect process heat users.

77 Without any markup by the EDB.

9.2.5 Transmission network charges

Where a consumer connects directly to the grid, Transpower will charge this consumer directly. Otherwise, they are passed through[78] by the local EDB.

The rules governing how Transpower charges its customers (distributors, directly connected industrials and generators) are determined by the Electricity Authority. These rules – known as the 'Transmission Pricing Methodology' (TPM).

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These changes come into effect for the 2023/24 pricing year[79].

The TPM is incredibly complex, and it is not possible to present the methodology in any detail here. In order to help process heat users understand these changes, we provide a commentary in Appendix C on what the TPM is trying to achieve, and what that might mean for charges that are passed through by EDBs to process heat users. We also provide a worked example.

9.2.6 Pricing summary

In summary this section has shown that process heat users considering electrification in the Northland region would face the following charges for electricity consumption:

- A retail tariff (including wholesale market and retail costs) which would **average around 11c/kWh over the next 15 years**, although the effective average tariff will differ between process heat users depending on the way their consumption varies over the year. Further, industrial process heat users may be able to secure special retail rates being offered by electricity retailers currently, which are significantly lower, in some cases, than 11c/kWh.
- A network charge which comprises components relating to the use of the existing distribution network, and Transpower's transmission network. These charges are structured in a range of different ways, and are specific to the part of the network the process heat user is in. We have approximated the published charges of the region's EDBs on a common per-MW (installed capacity) basis, suggesting the combined distribution and transmission charge **could (on average) be between $107,000/MW and $200,000/MW per annum, depending on the EDB.** However, we strongly recommend process heat users engage with the relevant EDB to obtain pricing that is specific to their location, operating profile, and desired capacity.

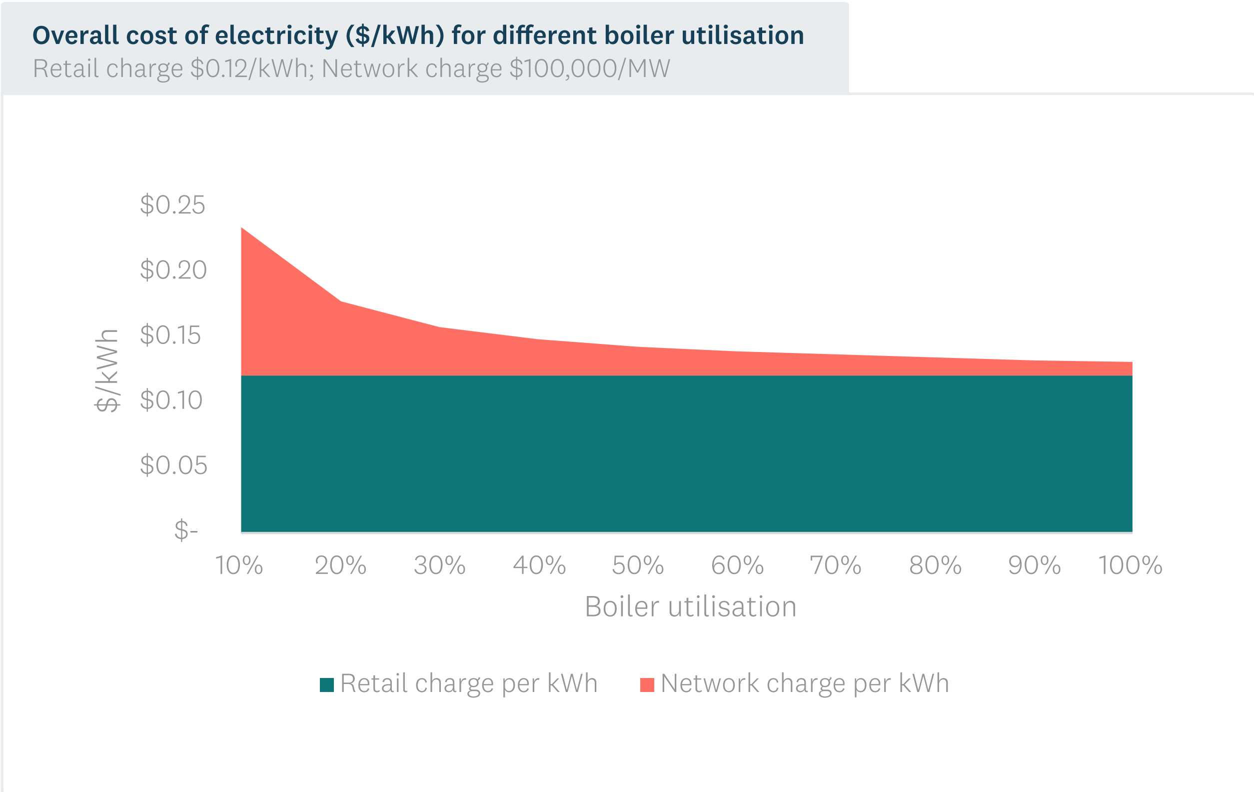
Combining these two types of charges into a single overall cost of electricity, to allow comparison with other fuels, requires an estimate of the utilisation of the heat plant (electrode boiler or heat pump). As discussed above, distribution charges are typically calculated as a function of variables that are often fixed (once the boiler or heat pump is installed) – connection capacity or anytime peak demand. As a result, for a given connection capacity (or peak demand), an electrode boiler or heat pump which has a high utilisation over the year will have a lower overall per-kWh cost of electricity than a site which only uses its boiler or heat pump for a shorter period (e.g. winter). This is illustrated in Figure 47, for example parameters of retail[80] and network charges.

[78] Without any markup by the EDB.

[79] A pricing year begins on 1st April for all network companies.

[80] As noted above, the retail rate itself will, in many situations, vary over the year under a 'time of use' retail plan. For simplicity, we have assumed a fixed retail rate over the year.

Figure 47 – Illustrative example of how overall cost of electricity varies with heat plant utilisation. Source: EECA



This doesn't mean that distribution charges can't be reduced. Rather, it means that opportunities to reduce them exist primarily at the design phase – optimising the size of the connection capacity and enabling flexibility in heat plant operation so that peak demand charges can be minimised. Appendix C discusses the opportunities and benefits from enabling flexibility in more detail.

The next section considers the third component of costs, which is the potential for RETA sites to need upgrades to the distribution network in order to accommodate the electrification of their process heat. This would require a capital contribution from the process heat user.

9.3 Impact of process heat electrification on network investment needs

EECA engaged Ergo to complete an assessment of the potential costs of transmission and distribution upgrades required to accommodate each individual RETA site, given the current capacity of the Northland networks. It is important to understand that this analysis was conducted to a level of accuracy commensurate with a 'screening' analysis and, necessarily, required Ergo to make a number of judgments and estimates. Each site contemplating electrification should engage with their EDB to obtain more refined estimates and potential options.

Further, accommodating new demand for electricity from process heat is not purely a matter of building new network assets. The degree to which network expansion is required can be influenced by the process heat user's willingness to be flexible in when they consume electricity and/or their willingness to have supply briefly interrupted on those very infrequent occasions when a network fault occurs. As outlined in Section 9.5, there are a range of ways that process heat users can benefit from being flexible, and EDBs are exploring ways in which customer response can be reliably integrated into their networks via operational arrangements and pricing incentives[81].

These opportunities are not included in Ergo's assessment of connection costs, and process heat users should engage with their EDB early to understand how their use of flexibility can reduce the cost of connecting, and what the operational implications are (see Appendix C for a fuller discussion on flexibility).

We would note that according to EDB disclosure information, maximum demand for each network is:

- Top Energy – 78MW
- Northpower – 78MW

If both EDBs reached their individual peak demands at the same time, the regional peak would be 235MW; however, Transpower reports that the 2022 regional peak demand was 226MW, indicating that there is some degree of regional diversity.

If all Northland RETA sites electrified, Northpower would experience the highest relative increase in maximum demand (55%), as compared to Top Energy (5%). Should the increase in both EDB's peak demand occur at the same time, this would represent a regional increase of 69MW, i.e. 31% increase on the 2022 regional peak demand.

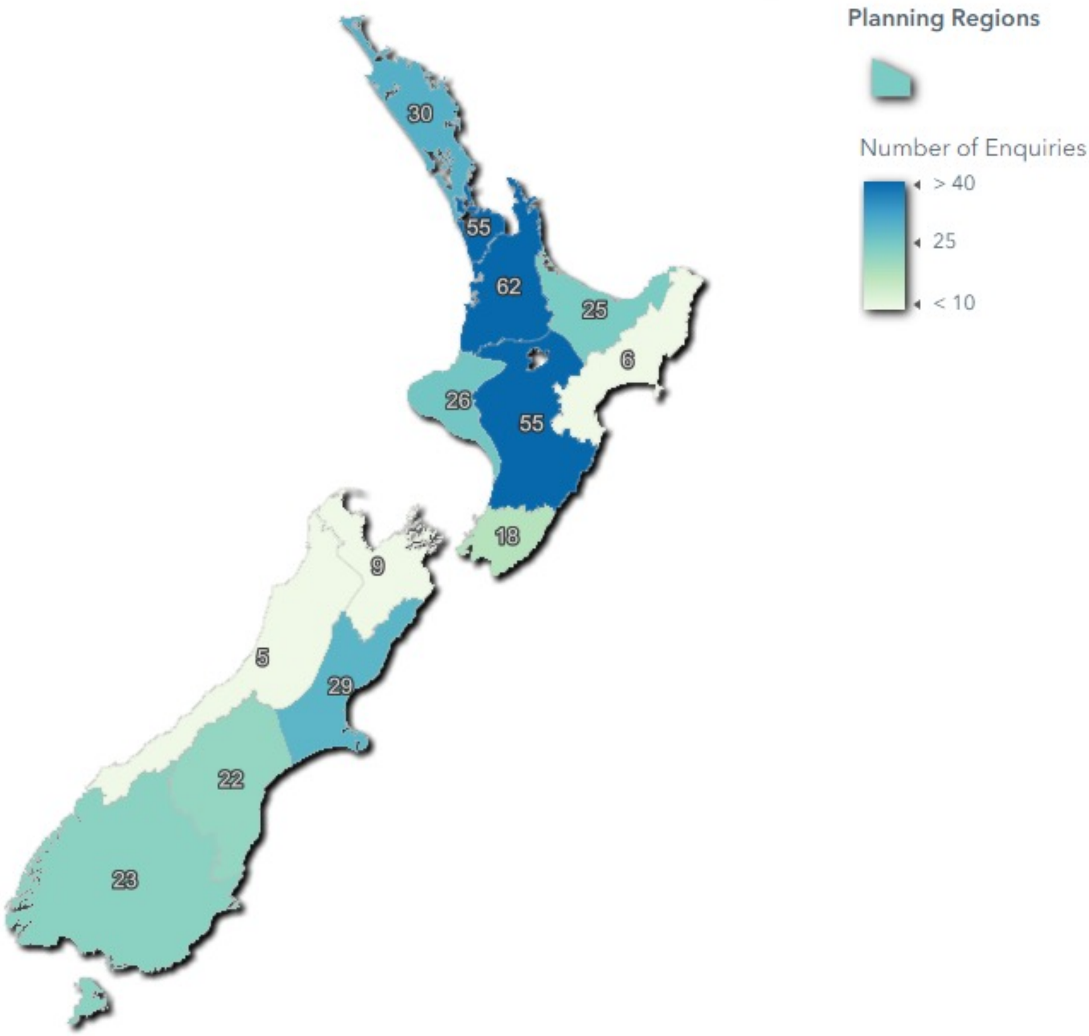
We stress that the assessment of spare network capacity, costs, and lead times presented below is changing all the time. The policy and regulatory space for the electricity sector is in a state of change as it incorporates decarbonisation and the emergence of new technologies. This in turn is leading to a greater number of consumers considering the technology they buy and how they reduce their consumption of fossil fuels. Hence Transpower and EDBs exist in a context which is changing far more quickly than it did, say, 20 years ago.

81 This is part of a broader development of 'non-network alternatives' by EDBs and Transpower – demand response from consumers, distribution-scale batteries, and distributed generation – to defer the need for more capital-intensive upgrades.

Specifically, Transpower and the EDBs are experiencing an increasing need for investment as a result of continued population and business growth, distributed generation, and the electrification of transport and process heat. While this RETA analysis only examines demand from process heat electrification, and public EV charging facilities where this information is available to EECA, this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

As an illustration of this, Figure 48 below shows the number of enquiries Transpower alone is facing in each of its planning regions. Of the 365 enquiries they face nationally, 68% have need dates prior to 2025[82]. Transpower reports that of the 52[83] enquiries in the Northland region, seven are for demand-side needs including network upgrades and EDB/Transpower demand connections. The remainder are for supply-side needs including grid-connected generation (29) EDB connected generation (12), as well as a grid-connected energy storage connection.

Figure 48 – Number of grid connection enquiries per region, October 2023. Source: Transpower



[82] As at October 2023.

[83] The regional figures on Transpower's map excludes any enquiries that are only prospects, commissioned, or 'Enquiries that have been assessed as unlikely to proceed to commissioning'. Our figures in the text report the total number of enquires.

It is going to be challenging for Transpower and EDBs to scale up their resourcing to cater to this new demand and proposed generation in the region.

The implication for the material presented in this section is that it is a snapshot in time, in an electricity industry that is rapidly changing – both on the supply (generation) side, and for consumers as they consider electrification.

9.3.1 Non-process heat demand growth

The assessment of spare capacity at each point in the network is based on near term estimates of peak demand published by network companies, combined with knowledge of peak demand at each RETA site. Should some of the sites proceed to electrification, a number of years may pass between now and when the connection and fuel switch is finally commissioned. In this intervening period, some degree of demand growth (outside the sites considered in this RETA) will occur due to:

- Increased residential demand from new houses.
- Increased business demand from business growth and/or smaller scale fuel-switching away from fossil fuels.
- Increased transport demand from the electrification of private and public transport vehicles.

Where possible, we have included additional public EV charging stations, where EECA are aware of these.

Each individual EDB will have developed peak demand forecasts over the next 10+ years that account for these factors. EECA understands these forecasts are shared with Transpower, as they develop their peak demand forecasts for each GXP.

Depending on the magnitude of growth in electricity demand, some of the spare capacity identified may be absorbed by the time each site finalises its connection arrangements. Hence the above analysis is a snapshot in time and has not considered the degree to which future demand growth may change which investments trigger an upgrade.

Matauri Bay, Northland, New Zealand. Credit – Pamela Edmondson.

9.3.2 Network security levels N and N-1

Before discussing the current state of the electricity network in the Northland region, it is important to define the security standards that are used to define the capacity of the network.

Electricity networks use a convention to describe the level of connection security they provide all customers at a particular connection point. Broadly, this convention distinguishes three levels of security:

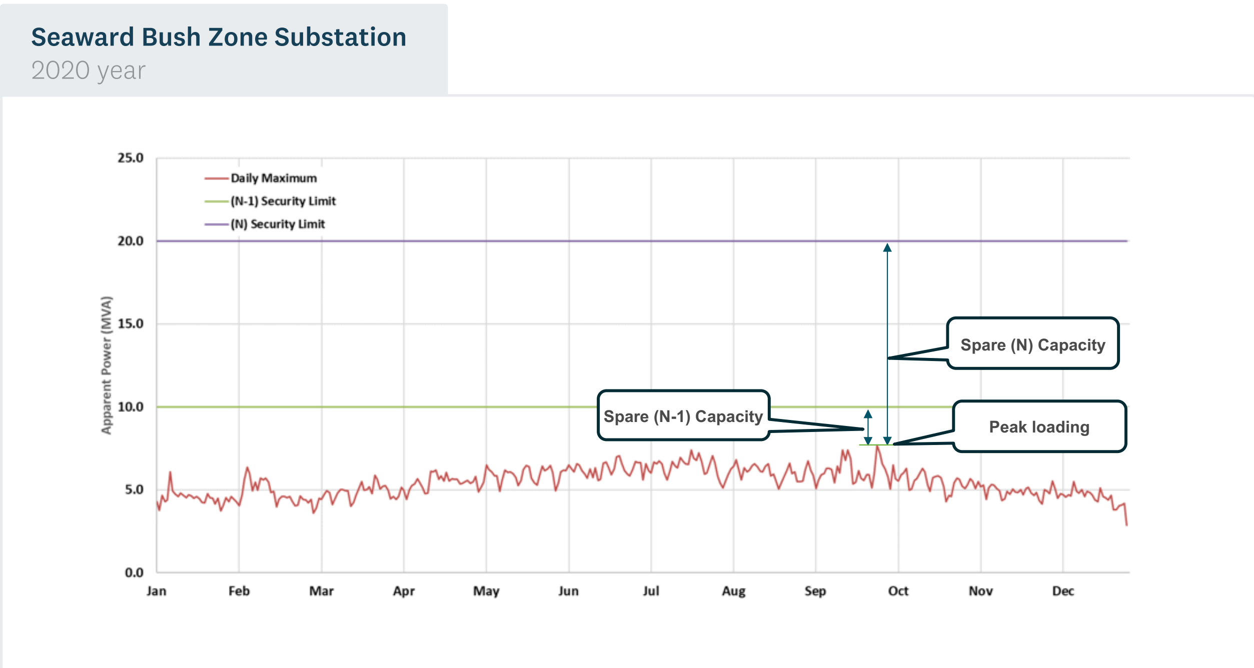
- **N-1 security** – Where N-1 security is present, forecast peak demand can be met and, furthermore, any 'credible' failure of a single component of the network (e.g. transformer or circuit) will also leave the system in a satisfactory state[84].
- **N security** – A failure of any single component of the network at forecast peak demand may result in a service interruption that cannot be restored until the fault is repaired.
- **Switched security** – Some EDBs, such as Northpower, also use a concept of 'switched' security where the EDB responds to a network event by switching a customer across to an alternative network asset. This switching may result in a short interruption, which may or may not suit the customer.

N-1 is generally provided through building redundancy into network assets, relative to the expected (peak) demand. It is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population.

In the distribution networks, the lower scale, coupled with higher network density, means providing the redundancy for N-1 to every customer would be very expensive. Hence, many parts of the distribution network only experience N security. This is discussed further in Appendix 11.1.5.

Figure 49 illustrates the difference between the available capacity for N and N-1 security for a zone substation.

Figure 49 – Illustration of spare N and N-1 security capacity at Seaward Bush zone substation. Source: Ergo



[84] This means that undue interruptions in supply or the spreading of a failure must not occur. Furthermore, the voltage must remain within the permitted limits and the remaining resources must not be overloaded.

If a customer agrees with the EDB to utilise N security capacity[85], there may be operational measures that would need to be put in place to ensure network security is managed in the event of a network fault. These operational measures will likely include a physical arrangement which automatically interrupts supply to the process heat user when a network fault occurs.

As discussed in Appendix C, current spare capacity may be more efficiently utilised through new process heat users enabling flexibility in their production processes (i.e. increasing load diversity). Such flexibility can either be made available to network companies should a network failure occur (i.e. the '1' in N-1), or could be used systematically to avoid breaching the N-1 limit in real-time (through, for example, demand shifting).

9.3.3 Impact on transmission investment

The electrification of the RETA sites will increase the electricity demand at the three of six regional GXPs and four of the EDB transmission substations shown on Figure 48 above. This has implications for both regional and GXP demand.

Regional considerations

As previously noted, the Northland regional demand is highly variable throughout the day with low loads overnight, especially in the summer months. There are long transmission lines transporting Central North Island generation to Northland, which can lead to either under or over voltage during varying system conditions. As the load in the Northland region increases, there will be an ongoing need for investment in voltage support equipment and efficient voltage management systems to manage the issue in the region.

From a transmission perspective, Transpower is responsible for maintaining and upgrading the national grid to ensure continuity of supply, which includes the management of voltage stability. However, with the unique situation where the Northland EDBs own 'ex-Transpower' assets (transmission substations, and in Top Energy's situation 110kV transmission lines), they also have a responsibility for managing voltage stability in the region.

To assist in managing potential voltage instability issues that occur in the Upper North Island (which includes Waikato, Auckland, and Northland regions), Transpower has voltage support equipment in each of the regions including located at Marsden in Northland. In addition, the Northland EDBs also have voltage support equipment within their networks to help control voltage variability.

Based on its location, topography and associated environmental conditions, the Northland region has a very high potential for renewable generation (geothermal, wind and solar). However, it should be noted that any new generation connection (either grid-connected or embedded within a distribution network) may exacerbate the voltage issues in the region. As such any investment in new generation may also require investment in additional voltage support equipment to manage voltages during light load and/or peak load periods.

[85] This includes situations where N-1 security is currently being provided to existing customers (often the case in urban centres), but the connection of a new process heat demand exceeds the spare N-1 capacity. In order to continue providing N-1 security to existing customers, an arrangement between the new process heat user and the EDB could be that the new process heat uses spare N capacity on the understanding that the EDB can automatically interrupt supply in the event of a network fault. This ensures that continuity of supply (i.e. N-1) is maintained to the existing customers, whilst at the same time limiting the investment required to accommodate the new process heat user.

Transpower notes in their 2022 Transmission Planning Report, that there is a wide range of interest in new generation developments in the Northland region within both the distribution network and Transpower's grid. The total amount of enquiries, and the predicted energy output, far exceeds the current transmission export capacity out of Northland back south into the load intensive Auckland area. Spare capacity exists to connect some level of new generation, however, the transmission capacity available is not cumulative. That is, generation injection at one location will reduce the capacity for additional generation at another location in the region. To facilitate the connection of all the proposed generation in the region, transmission and distribution network upgrades are likely to be needed, as well as investment in additional voltage support equipment and/or management practices.

Transpower is working alongside Top Energy and Northpower to investigate a Renewable Energy Zone (REZ) to promote fair and robust generation development in Northland[86].

In addition, as part of Transpower's Waikato and Upper North Island Voltage Management Investigation[87] project Transpower has investigated a number of investment options that could assist in the management of both current and future voltage support and thermal constraint issues in the upper North Island region. Any voltage support investments made under the WUNIVM project will also resolve voltage stability issues in the Northland region.

The options Transpower considered included a mix of transmission (including voltage support and battery storage), operational, generation, storage, and demand response (controlled load reduction, shifting or shedding) solutions. As previously noted, Transpower's approved major capital expenditure proposal includes a mix of voltage support mechanisms and a demand management scheme. These solutions are to be implemented at various locations and commissioned at different times in the future.

The demand response option provides an opportunity for loads with flexibility to offer a service where they reduce, shift, or shed load in response to a signal from Transpower (or the EDB), and receive payment for the service via a Grid Support Contract. Process heat users with this ability, are encouraged to discuss the option with Transpower or their EDB.

The inherent assumptions in our analysis for the Northland region are that:

- The transmission lines into the region have sufficient capacity to import the power needed to meet demand at all times.
- Transpower's investment programme (including the Waikato Upper North Island Voltage Management Investigation Project) will address the Upper North Island voltage stability issues noted over the next 5 to 10 years[88].
- There is always sufficient generation nationally[89] to generate the power required to be imported into the region.

86 See https://www.transpower.co.nz/renewable-energy-zones-northland-pilot-concept

87 https://www.transpower.co.nz/projects/waikato-and-upper-north-island-voltage-management-investigation

88 2022 Transmission Planning Report: section 6.5.1.1.

89 In terms of the sufficiency of generation nationally, since 1996, there has only been one instance where customers have had their power forcibly interrupted due to a national shortage of electricity generation (9th August 2012, which was subject to an extensive Ministerial Inquiry – the result of which suggested there may not have been a need to turn customers off, and there was in fact sufficient generation to supply the demand at the time). Looking forward, there is considerable work being undertaken in the industry to ensure that national (and island) security of supply is maintained as the electricity system transition towards more renewable supply.

- There is always sufficient Ngāwhā geothermal generation to provide voltage support and energy to the region.
- The grid backbone and regional grid voltage support mechanisms are sufficient to prevent voltage instability and/or voltage collapse in the region.

GXP level connection considerations

The available spare capacity for different security levels (N and N-1), at each of the Northland GXPs is shown in Figure 50. For the avoidance of doubt, Figure 56 shows the capacity headroom at each GXP, that is, the difference between Transpower's prudent demand forecast (for 2022) and the N or N-1 capacity at the GXP (as published by Transpower).

Also shown in Figure 50 are the Northland 'transmission substations', which are ex-Transpower assets which have been purchased by the EDBs in the area. These transmission substations are at a voltage level normally associated with Transpower GXPs (e.g. 110kV) which are then stepped down to a 'sub-transmission' level (e.g. 33kV). As such their operation and place in the network topography is such that these transmission substations are a lot more similar to GXPs than to normal sub-transmission zone substations, and hence have been included alongside Transpower's GXPs when considering spare capacity.

Figure 50 – Spare capacity at Transpower's Northland grid exit points (GXPs) and transmission substations. Source: Ergo

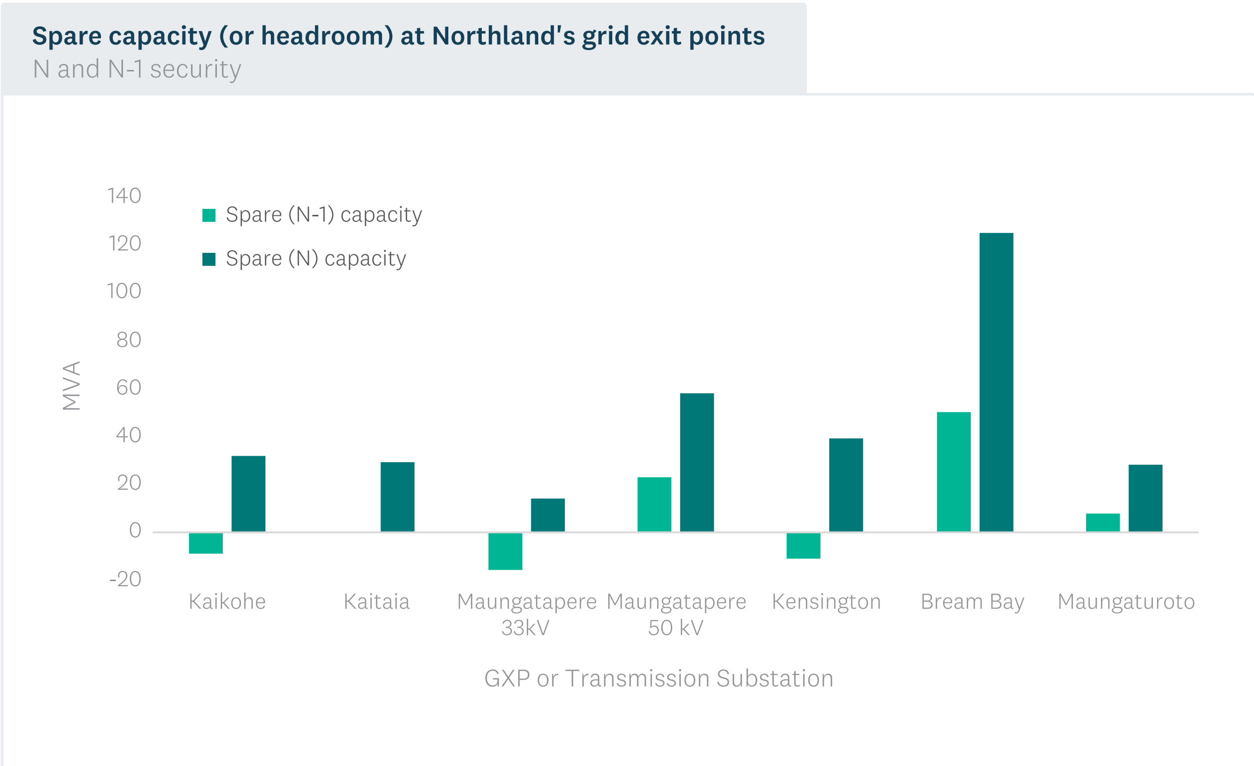


Figure 50 infers that only Bream Bay has a substantive level of spare (N-1) capacity, which is a result of the closure of the Marsden Refinery in 2022. There are modest levels of spare N-1 capacity at Maungatapere 50kV and Maungaturoto. Based on the 2022 forecast demands for the region[90], there is no spare N-1 capacity at Kaikohe GXP (assuming Ngāwhā generation is unavailable at the time), nor at Maungatapere or Kensington transmission substations, but there is spare N capacity at each of these locations. Kaitaia transmission substation has no N-1 spare capacity as it is supplied via a single 110kV circuit from Kaikohe, therefore can only operate at N.

We note that spare capacity at Kaikohe is complicated by the presence of significant embedded generation – particularly Ngāwhā geothermal generation, of which units OEC1-3 (25MW) are embedded and unit OEC4 (32MW) is grid connected. Ignoring the Ngāwhā generation, the Kaikohe GXP exceeds the (N-1) capacity of the 110 kV lines which supply it. However, considering the 25MW of embedded Ngāwhā generation (which connects to the network at 33 kV), the GXP has ~16 MVA of spare capacity in the lines supplying the GXP.

Noting that Ngāwhā generation is geothermal, it is considered to be reliably dispatchable, and therefore expected to be consistently generating to reduce the demand on Transpower and Top Energy's assets. The additional grid connected Ngāwhā generation unit (32MW) is likely to further support the N-1 capacity at the Kaikohe GXP[91]. Furthermore, Top Energy notes that with the expansion of Ngāwhā, the generation output can meet 125% of the far North's demand offtake[92], resulting at times with power being exported into the transmission network for use by consumers outside of Top Energy's area.

The spare capacities shown in Figure 50 do not include any voltage constraints or upstream transmission constraints, which would need to be confirmed by Transpower or the relevant EDB.

For those sites with limited spare capacity left, we comment below on any planned transmission upgrades[93]. These are summarised in Table 11.

90 From demand forecasts included in Transpower's 2022 TPR, and Top Energy and Northpower 2023 AMPs.

91 The 32MW Ngāwhā unit was not referenced in Transpower's 2022 TPR as part of their Kaikohe space capacity analysis, so the size of the contribution (if any) is not known.

92 See Top Energy 2023 AMP.

93 These are upgrades that are specifically planned by Transpower in their 2022 Transmission Planning Report (TPR). Future potential upgrades are also contemplated by the TPR, and may be the subject of discussions with EDBs, but are not costed or formally planned.

Golden Bay Cement, Northland, New Zealand. Credit – Golden Bay Cement.

Table 11 – Spare grid exit point (GXP) capacity in Northland and Transpower and the EDB's currently planned grid upgrades.

GXP	EDB	RETA sites analysed	Spare N-1 GXP/ transmission substation capacity	Planned Transpower GXP/ EDB transmission substation upgrade
Kaikohe GXP	Top Energy	• Northland Regional Corrections Facility • Imerys Ceramics New Zealand Ltd • Bay of Islands College • Kerikeri Crematorium	No Ngāwhā: None With Ngāwhā (25MW): 16MW	No GXP upgrade. Ngāwhā generation used to provide N-1 Top Energy plans to install a new 110/33kV substation at Wiroa to assist with the N-1 capacity issue in the event Ngāwhā is not generating. This includes installing two new transformers with the first being commissioned FY29.
Maungatapere 33kV	Northpower	• Downer Whangārei Asphalt Plant • Whangārei Hospital	None	Northpower manages capacity issues during lines outages by switching load between Maungatapere and Kensington transmission substations. Northpower has plans to restore an existing disconnected subtransmission (33kV) line and to upgrade the transformers from 30MVA to 100MVA to increase the N-1 capacity
Kensington	Northpower	• Fonterra Kauri • Grinning Gecko Cheese Company[94] • Northland Polytechnic • Whangārei District Council Aquatic Centre • Whangārei Girls High School • Whangārei Boys High School • Whangārei Council Maunu Cemetery	None	Northpower is upgrading the substation with two new transformers increasing the N-1 capacity to 100MVA. The upgrade is due to be completed in 2026

[94] Ceased operation in early 2023.

GXP	EDB	RETA sites analysed	Spare N-1 GXP/ transmission substation capacity	Planned Transpower GXP/ EDB transmission substation upgrade
Bream Bay	Northpower	• Bream Bay College	50MW[95]	None required
Maungaturoto	Northpower	• Fonterra Maungaturoto • Otematea High School	8MW	None

Assessing the transmission grid implications of connecting RETA sites against current spare capacity is only part of the story:

- In some of the cases above where no spare capacity exists today, the planned upgrades in Table 15 will accommodate the connection of new electrified process heat users.
- At GXPs where there are no planned upgrades, the connection of multiple RETA process heat sites may be so significant that an upgrade – not currently planned by Transpower – is triggered.
- There may be some situations where there is insufficient spare N-1 capacity, but a process heat user may be able to either connect at N security – requiring it to be able to reduce demand should a contingency occur – or be able to reduce its demand at peak times to avoid breaching the existing N-1 limit. This is covered further in Section 9.5.

For the Northland region, Ergo's analysis concluded that for the majority of the GXPs and transmission substations the already planned network upgrades by the respective EDBs means only one RETA site, by itself, could trigger the need for further transmission upgrades at these sites. This site is the electrification of the Fonterra Maungaturoto RETA site – which consists of a number of stages and would result in the exceedance of the (N-1) capacity available at the Maungaturoto 33kV, thus triggering upgrades to both the distribution and the transmission networks at Maungaturoto.

Section 9.4 considers whether the collective connection of multiple RETA sites at a GXP or transmission substation may lead to a need for transmission investment[96].

95 The closure of the Marsden Refinery has resulted in an approximate 30MW reduce in load.

96 Where grid upgrades are triggered by the collective decisions of multiple organisations (potentially generators and consumers), it falls into the realm of the TPM, which is discussed more in detail in Section 9.2.5 above.

9.3.4 Analysis of impact of individual RETA sites on EDB (distribution) investment

The majority of RETA sites will connect to the distribution (rather than Transpower's transmission network). Here we present an analysis of whether the existing distribution network can currently accommodate each RETA site, and, if not, what the options are to upgrade the network sufficiently.

It is important to emphasise that the analysis undertaken here is preliminary and not intended as a detailed guide to the scope of works required to connect each site. The intended purpose is to provide a high-level 'screening' of process heat sites and the likely magnitude and complexity of their connection arrangements, should they choose to electrify. Further, the connection costs below approximate the total capital cost of constructing the connection assets, which may overstate the cost faced by the process heat user due to the potential for capital contributions from the EDB. It is imperative that process heat owners seek more detailed assessments from the relevant EDB (and potentially Transpower) should they wish to investigate electrification further or develop more robust budgets[97].

Below we present the results of Ergo's analysis of the RETA sites in three sections, reflecting the potential connection complexity of each site:

- **Minor** – The 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Some connections may require infrastructure which takes additional time to procure from international suppliers or implement (e.g. transformers, underground cabling).
- **Moderate** – The 'as designed' electrical system requires some infrastructure upgrades including new connections into the local zone substation, upgrades at the local zone substation, and/or upgrades to the sub-transmission[98] network.
- **Major** – The 'as designed' electrical system requires large upgrades at both the transmission and distribution level, likely requiring substantial investment, potentially with lead times beyond 36 months.

All estimates exclude the timeframes required for consenting and easements, if required. The categorisation of the projects does reflect the complexity of the potential work required and actual costs may differ from the indicative figures provided here. Also, since the assessment of upgrades required are limited to those that the process heat user would pay the EDB for directly (i.e. they are customer-initiated investments) there is no need for approval from the Commerce Commission. Were this not the case, the timelines for regulatory approval would need to be added to the timelines below.

Given the speed at which information is changing, the information presented below is indicative, and is a snapshot in time. Estimates are conservative. Each individual site should be re-considered when more detail is available.

In particular, the nature of information available at the time of this assessment, and the complexity of the task, necessitated a set of assumptions about how the various sites could be accommodated within the network. Detail pertaining to these assumptions can be found in the Appendix 11.1.6.

97 Cost estimates have a Class 5 accuracy - suitable for concept screening. See https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

98 The network infrastructure which connects local zone substations to Transpower's GXP.

It should be noted that the cost estimates provided by Ergo only include the incumbent network operator's distribution/transmission equipment up to the customer site boundary and do not include onsite equipment that may be required to supply each site (for example, switchboards/cables within the respective sites are not included).

The magnitude of these additional onsite costs depends on whether the new process heat equipment (heat pump or electrode boiler) can be accommodated within the site's existing connection capacity. For larger installations (>1MW), it is unlikely that any current spare onsite capacity will be sufficient, and an allowance is made for these costs in the estimated boiler or heat pump cost (rather than in the table below). However, for smaller sites (the majority of which appear on the 'minor' complexity table), it is possible that existing spare capacity can accommodate the new plant without significant additional expenditure.

However, there is no practical way, as part of the RETA planning phase analysis, to discover whether smaller sites have spare onsite connection capacity, or whether that spare capacity is sufficient to accommodate new electrical loads for process heat. In the cost tables below, we indicate the potential for these costs to arise by having a minimum network upgrade cost of <$0.3M.

Table 12 lists the connections that are categorised as 'minor' in nature.

Russell, Northland, New Zealand. Credit – Top Energy.

Table 12 – Connection costs and lead times for minor complexity connections. Source: Ergo

Site	Transpower GXP/EDB transmission substation	Network	Peak site demand (MW)	Total network upgrade cost ($M)[99]	Timing[100]
Northland Regional Corrections Facility	Kaikohe	Top Energy	2.90	<$0.3	3-6 months
Imerys Ceramics New Zealand Ltd	Kaikohe	Top Energy	1.36	<$0.3	3-6 months
Bay of Islands College	Kaikohe	Top Energy	0.30	<$0.3	3-6 months
Kerikeri Crematorium	Kaikohe	Top Energy	0.20	<$0.3	3-6 months
Downer Whangārei Asphalt Plant	Maungatapere	Northpower	5.00	$0.9	6-12 months
Whangārei Hospital	Maungatapere	Northpower	4.46	$1.6[101]	6-12 months
Grinning Gecko Cheese Company[102]	Maungatapere	Northpower	0.67	<$0.3	3-6 months
Northland Polytechnic	Maungatapere	Northpower	0.36	<$0.3	3-6 months
Fonterra Kauri - Stage 1 (N-1 supply option)	Kensington	Northpower	1.0	<$0.3	3-6 months
Whangārei District Council Aquatic Centre	Kensington	Northpower	0.24	<$0.3	3-6 months
Whangārei Girls High School	Kensington	Northpower	0.24	<$0.3	3-6 months
Whangārei Boys High School[103]	Kensington	Northpower	0.20	<$0.3	3-6 months
Whangārei Council Maunu Cemetery	Maungatapere	Northpower	0.20	<$0.3	3-6 months
Bream Bay College	Bream Bay	Northpower	0.17	<$0.3	3-6 months
Otamatea High School	Maungaturoto	Northpower	0.17	<$0.3	3-6 months

99 We reiterate that for sites with increases over 1MW, these costs do not include costs associated with the installation of distribution transformers/switchgear on the site. These costs are included as part of the assumed overall capital cost of boiler installation (see Section 7.1).

100 If a distribution transformer and/or switchgear is required, the lead time is expected to be around 9-12 months.

101 Due to the 11kV capacity being very limited, we expect this connection would have to connect to the 33kV network, resulting in a higher cost, a moderate connection complexity, and potentially a longer lead time.

102 Has since ceased operation (early 2023).

103 We understand that since the analysis was completed, this project has been confirmed.

Table 13 lists the connections that are categorised as ‘moderate’. These connections are more significant, both in terms of cost and the estimated time required to complete.

Table 13 – Connection costs and lead times for moderate complexity connections. Source: Ergo

Site	Transpower GXP/EDB transmission substation	Network	Peak site demand (MW)	Total network upgrade cost ($M)	Timing
Fonterra Kauri - Stage 2 (N supply option)	Kensington	Northpower	9.35	$1.6	12-30 months
Fonterra Kauri - Stage 2 (N-1 supply option)	Kensington	Northpower	9.35	$9.6	12-30 months
Fonterra Kauri - Stage 3 (N-1 supply option)	Kensington	Northpower	17.70	$10.8	12-30 months
Fonterra Kauri - Stage 4 (N-1 supply option)	Kensington	Northpower	26.05	$10.8	Not specified

Table 14 shows the one connection that is categorised as ‘major’. These connections are significant, in terms of cost, complexity and the estimated time to complete.

Table 14 – Connection costs and lead times for major complexity connections. Source: Ergo

Site	Transpower GXP/EDB transmission substation	Network	Peak site demand (MW)	Total network upgrade cost ($M)	Timing
Fonterra Maungaturoto – Stage 1 (N-1 security)	Maungaturoto	Northpower	8.0	$0.4	12-24 months
Fonterra Maungaturoto – Stage 2 (N security)	Maungaturoto	Northpower	15.0	$6.9	12-24 months
Fonterra Maungaturoto – Stage 2 (N-1 security)	Maungaturoto	Northpower	15.0	$7.8	12-24 months
Fonterra Maungaturoto – Stage 3 (N-1 security)	Maungaturoto	Northpower	28.43	$31.4	24-36 months

Fonterra Maungaturoto is currently connected to the Maungaturoto GXP which, as outlined in Section 9.3.3, has 8MW of spare N-1 capacity and 28MW of spare N capacity. The costs noted in the table above are cumulative, as each latter stage is dependent on the prior stages being completed.

The proposed electrification of Fonterra's process heat involves three stages:

- Stage 1 (8MW), which can be accommodated with a new dedicated feeder from Maungaturoto but would be operating near its N-1 capacity limit.
- Stage 2 (15MW). The increase of an additional 7MW from Stage 1 (totalling 15MW of new load) will exceed Maungaturoto GXP's N-1 capacity limit but is within the N capacity limit. A special protection scheme[104] which would require the plant to disconnect during network events would likely be required. To retain N-1 capacity another line between Maungaturoto GXP and zone substation would be required. It is likely that a new 33kV switchboard would be required, which would involve the installation of a new switch room building, at an increased cost.
- Stage 3 (28.43MW). Following on from the completion of Stage 2, the size of this final stage is such that, in order to provide N-1 security, an upgrade of the Maungaturoto GXP, including transformer replacement, and potentially a new 33kV indoor switchboard, would be required. Due to the size of the load, additional 33kV voltage support is also likely to be required at the Maungaturoto zone substation, at the GXP (as a transmission asset), or locally at the Fonterra site.

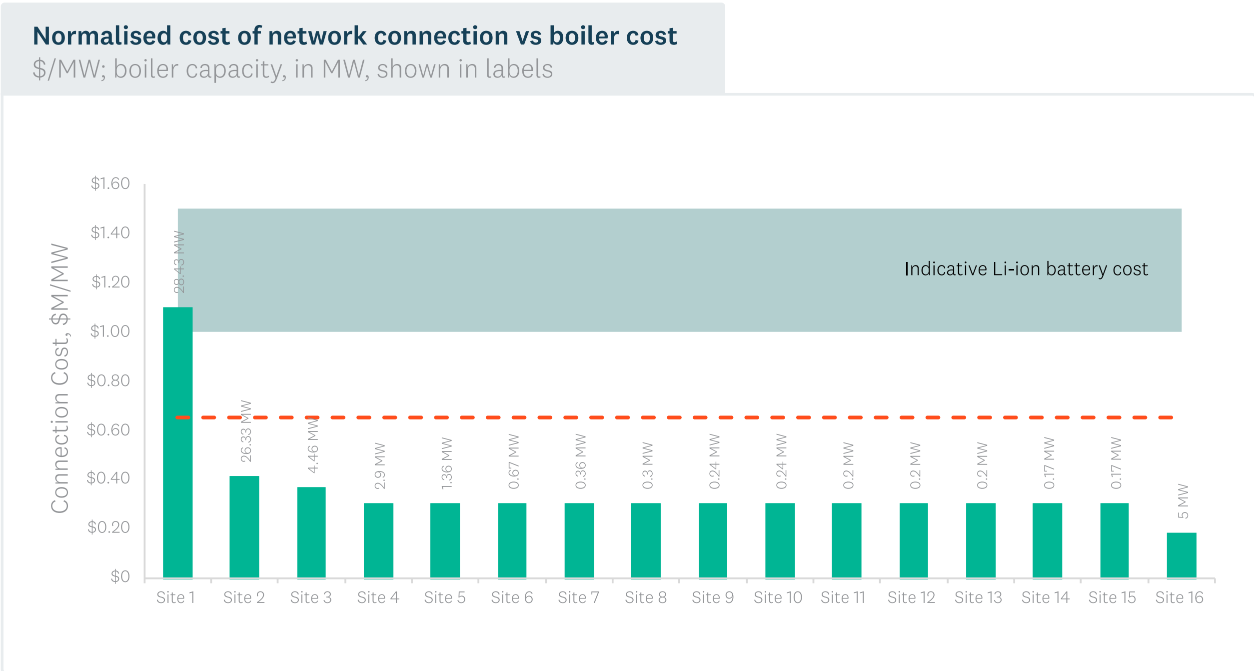
Noting the complexity of the Fonterra site above, and the likely impact on both the distribution and transmission networks, this underscores the importance of early and regular communication between process heat users, distributors and Transpower. EDBs and Transpower will be in a better position to optimise network investment when they have a more complete picture of the intentions of process heat users. This leads to cost savings which are likely to improve the business case for converting process heat to electricity.

[104] Refer to Appendix C, Section 13.1.5

9.3.5 Summary

The network connection costs presented above vary in magnitude. It is worth viewing these costs through the lens of the size of the boiler installation. Figure 51 shows each site's connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler, and to a lithium-ion battery solution.

Figure 51 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 51 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW[105]). The blue shaded area indicates the estimated cost range for a 1MW battery. Figure 51 shows not only a wide variety of relative costs of connecting electrode boilers, but that for one case, the connection cost almost doubles the overall capital cost associated with electrification and is within the indicative cost range for a battery energy storage solution (BESS).

Process heat users could potentially deploy battery energy storage solutions – or any other suitable storage solution (e.g. hot water, ice slurry etc) – to defer the need for transmission or distribution network investments by meeting peak demand with energy that was stored onsite during lower-demand periods. This helps reduce congestion and improves overall transmission and distribution asset utilisation.

We would note that while storage solutions (such as batteries, hot water, ice slurry etc) are highly valuable in managing peak periods, they can only do this for a limited period of time (e.g. a BESS generally has storage capability of a small number of hours depending on battery size, characteristics and configuration).

105 This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 7.

For the RETA site where the cost of a battery is nominally less that the possible connection costs, consideration should be given to investigating battery energy storage solution options, especially if the load profile has a peak that coincides with the relevant network daily peaks. In these situations, the use of a BESS could not only reduce network connection costs[106], but also provide an opportunity for the RETA site to offer (and contract) the operation of the BESS as a network peak management service to the EDB (or Transpower), such that the need for transmission or distribution investment is deferred.

We note, as explained above, the connection costs developed in this section, and used in Figure 51, may not reflect the capital costs incurred by the process heat user. EDBs may only charge the user a share of these costs, as per each EDB's capital contributions policies.

While the estimates of connection costs provided here are of an accuracy commensurate with this screening analysis, it does demonstrate how connection costs can have a significant effect on the final decision. It also shows that, particularly for smaller electrification projects, reductions in connection cost of only $50,000 could have a significant effect on the economics of fuel switching decisions.

Transmission lines, Northland, New Zealand. Credit – Top Energy.

[106] The degree to which a battery can do this depends on the demand profile of the site. If, as discussed above, the site reaches its peak demand for very short periods (30-60 minutes), a BESS may be suitable. However, if it sustains its peak load for a number of hours, batteries may be less economic than network upgrades.

9.4 Collective impact of multiple RETA sites connecting

The above analysis considered each site in isolation from each other, and whether it could fit into the spare capacity available in existing network infrastructure. This may underestimate the need for wider network upgrades, should a number of RETA sites choose to electrify and thus – collectively – have a more significant impact on peak network demand.

9.4.1 Diversity in demand

In considering scenarios where multiple sites electrify their process heat and connect to common network infrastructure, we must first consider what the resulting collective peak demand is. A simplistic approach would be to sum the individual peak demands of each RETA site and add them to the existing peak demand on the network. However, RETA sites may have quite different patterns of demand over the year – some peak in winter (swimming pools, schools) while others (e.g. dairy) peak in summer. In other words, not all individual site 'peaks' happen at the same time. Further, they may not occur at the same time as the existing demand peaks. Hence a better approach is to consider the diversity in the operational requirements of each RETA site, which may see each site:

- Reach its peak demand at a different time to the other RETA sites.
- Reach its peak demand at a different time to existing network demand.

If we can simulate the operational profiles of each site, we can approximate the extent to which diversity in peak demands leads to a lower overall peak demand on the network than the simple addition of each site's peak.

Determining the collective impact on peak demand requires detailed data on the profile of existing demand over the year, as well as similarly detailed data for each individual RETA site. Ergo obtained half hourly historical demand data for each Northland GXP for 2022, as well as simulated individual site profiles based on other similar sites. This allowed a simulation of what half-hourly demand at each GXP would have looked like in 2022, had all RETA sites been electrified.

Figure 52 illustrates this approach for the Maungatapere 33kV transmission substation. The top chart shows the half hourly demand at Maungatapere 33kV over the 2022 year. Below that, we show the simulated half-hourly demand profile of each RETA site, should they choose to electrify their process heat. The bottom chart shows the simulated resulting demand at Maungatapere 33kV, should these sites electrify their process heat. We reinforce that this more detailed analysis is a simulation based on 2022 data, hence is only indicative of the collective effect of these sites connecting, as though that happened in 2022. A more robust analysis would require consideration of future changes to half-hourly demand at Maungatapere 33kV transmission substation, including underlying growth from sources other than RETA sites.

Figure 52 – Simulation of impact on Maungatapere 33kV GXP demand from all RETA site electrification. Source: DETA, EECA

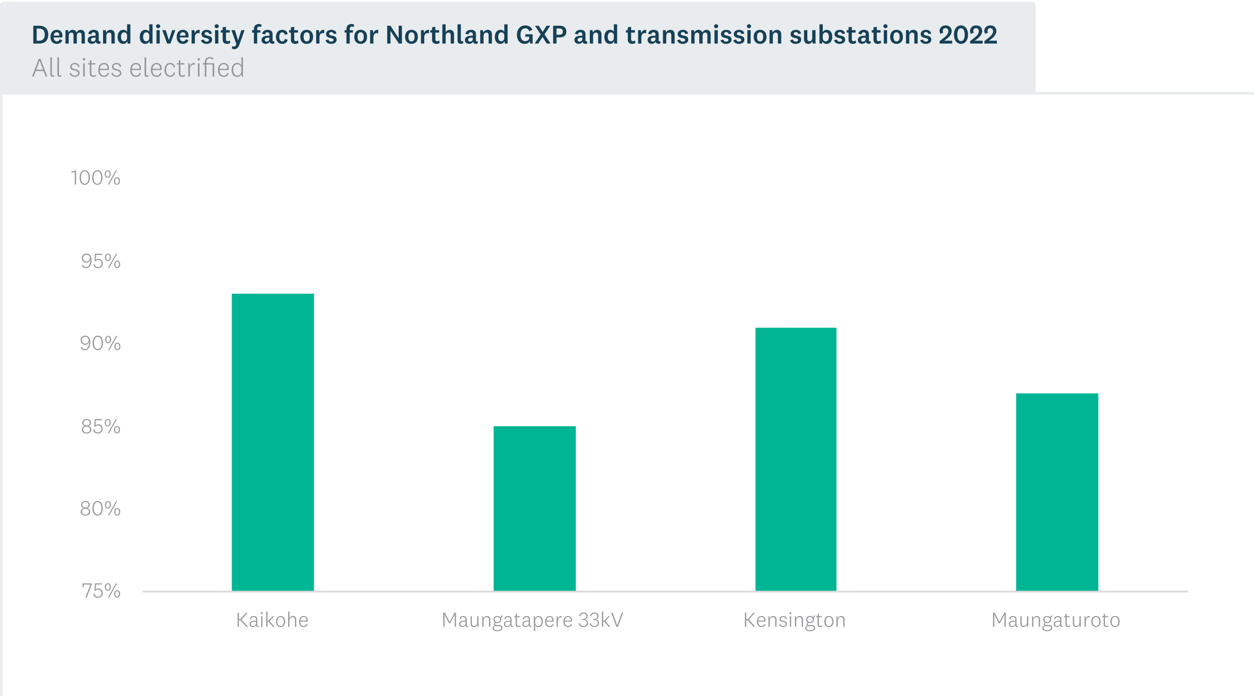
Importantly, the resulting peak GXP demand observed is 46.9MVA[107], which is lower than the simple addition of all individual RETA site peaks (10.6MVA) to the 2022 Maungatapere 33kV peak demand (44.5MVA), which would have suggested the new peak is 55.1MVA. The effect of demand diversity amongst the different Maungatapere 33kV RETA sites is that the combined peak is 85% of what a simple addition would have suggested. We refer to this as a diversity 'factor'.

[107] Here we use mega-volt-ampere (MVA) as the unit of demand. The analysis above has used mega-watts (MW) as the more conventional unit of demand. The difference between the two relates to accounting for reactive power. In most cases the difference is minor.

It should be noted that while the diagrams above show the Maungatapere transmission substation's N-1 limit is expected to be exceeded, network upgrades to mitigate the overloading issues are already planned, and once completed are viewed as adequate to supply the increased load due to the load sites.

Ergo repeated this analysis across four of the seven GXP/transmission substations[108]. The resulting demand diversity factors are shown in Figure 53.

Figure 53 – Demand diversity factors for Northland GXPs and transmission substations. Source: Ergo



We would note that according to EDB disclosure information, maximum demand for each network is:

- Top Energy 78MW
- Northpower 157MW

If both EDBs reached their individual peak demands at the same time, the regional peak would be 235MW; however, Transpower reports that the 2022 regional peak demand was 226MW, indicating that there is some degree of regional diversity.

If all Northland RETA sites electrified, Northpower would experience the highest relative increase in maximum demand (55%), as compared to Top Energy (5%). Should the increase in both EDB's peak demand occur at the same time, this would represent a regional increase of 69MW, i.e. 31% increase on the 2022 regional peak demand.

[108] The maximum load on Bream Bay GXP is not expected to change, and Kaitaia and Maungatapere 50kV have no planned RETA sites so no diversity analysis was required for these GXP/transmission substations.

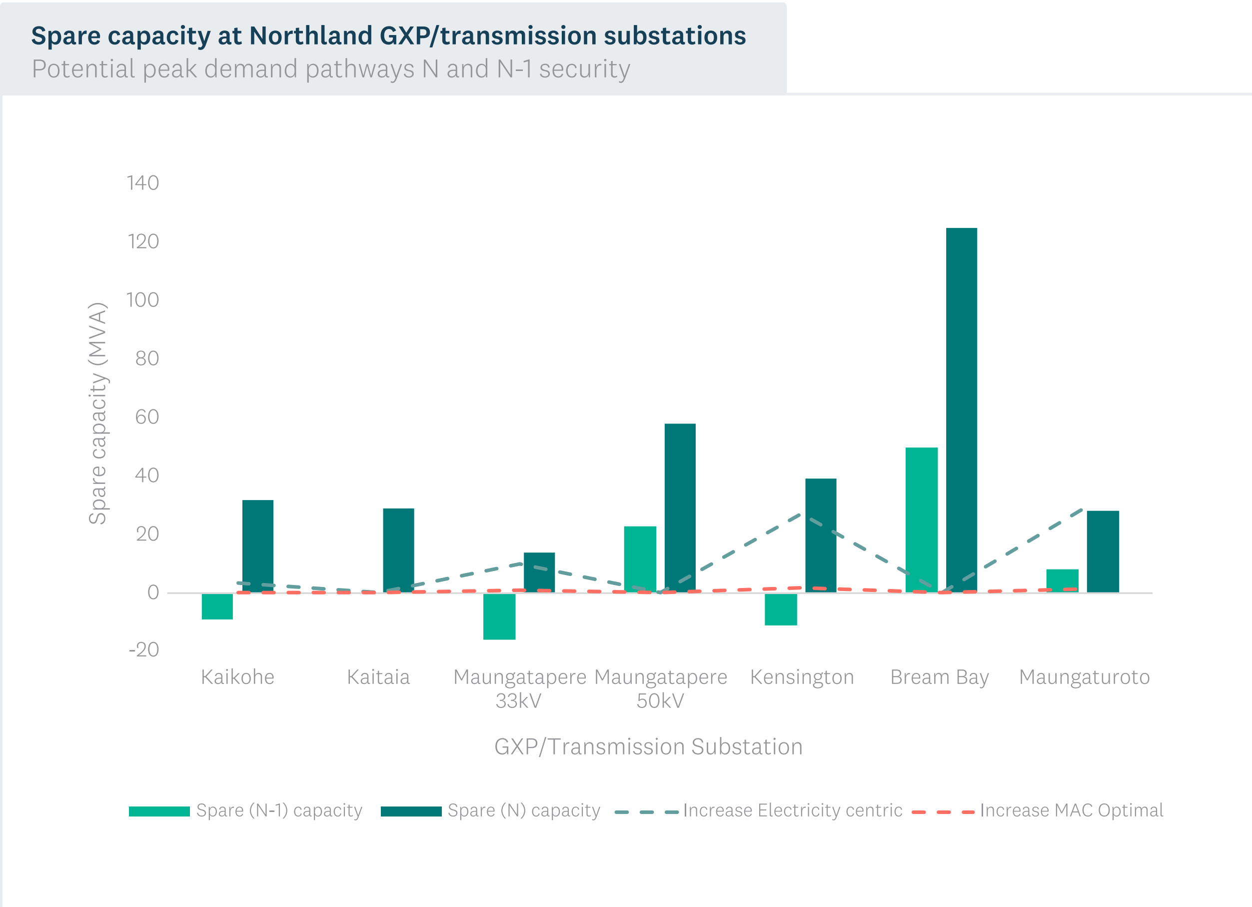
9.4.2 Assessment against spare capacity

We can use these diversity factors to determine the impact of all sites electrifying on spare capacity. Figure 54 shows the amount of spare capacity at each GXP if that would be used under two scenarios:

- The Electricity Centric pathway, where all unconfirmed Northland RETA sites choose to electrify (orange dashed line).
- A MAC Optimal pathway, where only those unconfirmed sites that have lower marginal abatement costs than biomass (see Section 7.1) electrify (blue dashed line).

Section 7.2 describes these scenarios more fully. Note that the dashed lines in Figure 54 assume that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand.

Figure 54 – Potential combined effect of site decisions at each GXP/transmission substation on spare capacity. Source: Ergo



On this analysis:

- In the Electricity Centric scenario, Bream Bay has significant N-1 capacity to accommodate the RETA demand. Comparatively, with Ngāwhā generation unavailable, Kaikohe has no N-1 capacity, however with Ngāwhā generation operating (25MW), there would be spare N-1 capacity at Kaikohe. Maungatapere 33kV and Kensington have no spare N-1 capacity, and RETA demand at these transmission substations would use up some of the spare N capacity. RETA demand at Maungaturoto causes both N and N-1 spare capacity to be exceeded.
- However, in the MAC Optimal scenario, there is very little increase in electricity demand. Noting that Kaikohe (with no Ngāwhā generation), Maungatapere 33kV and Kensington already exceed the N-1 capacity, the RETA demand will exacerbate the issue. The RETA demand under the MAC Optimal scenario at these locations would use up a small amount of spare N capacity.

However, as outlined earlier, our spare capacity metric is based on the difference between N-1 (and N) capacity at the GXP/transmission substation and Transpower's conservative prudent demand forecast. This forecast is a '90th percentile' forecast – that is, a somewhat worst-case assessment of peak demand. This forecast will, in many cases, be above the 'expected' peak demand.

Process heat users contemplating electrification at all nodes should engage early with Top Energy or Northpower to ensure that this assessment of spare capacity aligns with their expectations. These organisations will have a broader perspective of other demand growth (and distribution generation) expected to occur at the various GXPs, transmission substations and zone substations.

9.4.3 Zone substations

The assessment of the two RETA pathways against spare GXP and transmission substation capacity suggested that the majority of the process heat decarbonisation projects were unlikely to trigger network upgrades that were not already planned for. With the planned network investments at the transmission substation level, no potential upgrades to distribution zone substations were identified.

10 Northland RETA insights and recommendations

The RETA aims to develop an understanding of what is needed to decarbonise a region through a well-informed and coordinated approach. The focus is to understand unique region-specific opportunities and barriers when developing regional energy transition roadmaps.

This report has considered several organisations facing the decision of how to reduce their fossil fuel process heat consumption.

The aim of this report, which is the culmination of the RETA planning stage for the Northland region, is to:

- Provide process heat users with coordinated information specific to the region to make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities, and recommendations.

The report is premised on the observation that, while individual organisations may be able to obtain information pertinent to their own decarbonisation decision, some of the most important factors require a collective, regional view. Only with a regional view can 'system-level' challenges and opportunities be evaluated. If these challenges can be addressed, and opportunities pursued, process heat consumers and fuel suppliers can make better decisions.

This report has illustrated a range of decarbonisation pathways, all of which demonstrate how the combined decisions of a range of process heat users may lead to common infrastructure challenges from a supply perspective. The pathways illuminate different decision-making frameworks that might be used by process heat organisations to decide on which fuel to switch to. The pathways give a sense of the diversity of outcomes that might be expected.

In this section, we will present our findings from the work undertaken and recommendations about how the identified challenges can be resolved.

A 'whole-of-system' perspective would go further than this RETA to incorporate other sectors. The transport[109] sector will, likely, decarbonise through a combination of sustainable fuels (including bioenergy and electricity), and in some situations process heat and transport will compete for the same sources of fuel. The nature of the decarbonisation technologies that underpin these decisions is changing quickly, and a system-level view – even at a regional level – will allow decision makers and policy makers to be able make informed choices and identify challenges, gaps, and opportunities. This makes a RETA more complex, but more insightful in identifying system challenges and solutions.

[109] The analysis presented in Section 9.3 included some proposed public charging infrastructure for electric vehicles.

10.1 Biomass – insights and recommendations

The analysis above shows that comprehensive extraction and conversion of estimated processor and harvesting residues (after the deduction of the existing consumption of these residues) has the potential to supply the biomass demand arising under all pathways modelled.

Cutover residues may be more complex and more expensive to recover than modelled here, although we have used a pragmatic assessment based on expert opinion.

Our analysis suggests there are likely to be 17 process heat users seeking biomass as a fuel (including confirmed fuel switching projects). There needs to be a high degree of coordination between these organisations and forestry companies to ensure all parties – on the supply side and demand side – have the confidence to extract, process and consume residue-based biomass as a long-term option. There are a number of opportunities to increase this coordination and confidence, including:

- More analysis, pilots and collaboration with existing forestry organisations extracting residues (e.g. Port Blakely in South Canterbury) to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering residues.
- In tandem, work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.
- The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the 'integrated model' of cost recovery, outlined above, achieve the best outcomes in terms of recovery cost and volumes.
- Mechanisms should be investigated and established to help give confidence over prices, volumes and contracts for example regular (e.g. annual) updates to the biomass analysis in this RETA, encouraging use of industry-standard long-term contracts for process heat service-level biomass supply[110] and greater transparency about (anonymised) prices and volumes being offered or traded.
- Analysis is also required to determine the impact of recovering these residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.
- Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.

110 See https://www.bioenergy.org.nz/documents/resource/Technical-Guides/TG06-Contracting-to-deliver-quality-wood-fuel.pdf for a guide developed by the Bioenergy Association to assist the sellers and purchasers of solid biofuels trade and contract these materials for the production of energy.

10.2 Electricity – insights and recommendations

Electricity has a more established delivery infrastructure, and a market for securing medium-term supply of electricity at relatively stable prices through retail contracts.

Process heat users will make the best decarbonisation decisions if they clearly understand the potential costs and how enabling flexibility in their consumption will help reduce those costs (see Appendix C). Transpower and EDBs can only make the best decisions about upgrades if they have the best information about process heat organisations' intentions, and realistic levels of flexibility that process heat organisations can offer.

This RETA has sought to increase the level of information shared, but we acknowledge that the world is changing quickly and this needs to be a continued process. The more up-to-date information is, the better able organisations are to adapt to a changing world. Electricity industry participants need to find ways to increase the pace of information exchange.

As noted above, it appears unlikely that the conversion of RETA process heat to electricity will trigger significant transmission upgrades. However, there are some potential situations where EDBs will need to upgrade zone substations to accommodate some scenarios of fuel switching. It is critical that process heat users engage with EDBs early, and often, about their plans.

10.2.1 The role we need EDBs to play

Given the pace of change, EDBs need to proactively engage with process heat users in order to:

- Stay abreast of process heat users' intentions regarding timing of, and capacity required for, electrification decisions. This will enable EDBs to accommodate their intentions in their network plans and demand forecasts, to make efficient use of network resources.
- Help Transpower and other stakeholders (as necessary) receive information from process heat users relevant to their planning at an early stage.
- Provide process heat users with timely advice and a good understanding of network investment, and network security levels, that can be incorporated into process heat business cases.

A related opportunity is for the network companies to provide a stronger coordinating function for each region's large electrification initiatives.

To support early engagement, we recommend EDBs explore, in consultation with process heat users and EECA, the development of a 'connection feasibility information template' as an early step in the connection process[111]. This template would include a section for process heat users to provide key information to EDBs, and a network section where EDBs provide high-level options for the connection of the process heat user's new demand. Information provided by EDBs would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer's flexibility.

111 We are grateful to Otago EDB Aurora for raising this idea with us.

10.2.2 Information process heat organisations need to seek from EDBs and (if relevant) Transpower:

- **What their likely electricity consumption means for network upgrades** – The screening-level estimates provided in Section 9 provide a starting point, but more detailed discussions and engineering studies are required to firm these up. An important piece of information here is how the process heat user's demand (see below) aligns with existing demand patterns on the relevant parts of the network.
- **The risks and cost trade-offs of remaining on N security relative to N-1 (or switched N-1 if available)** – The EDB will have sufficient history of network outages to provide a realistic expectation of the frequency of network interruptions, as well as the duration of any interruption to supply.
- **Network charges and network loss factors relevant to their connection location** – As outlined in Section 9, we have estimated an average level of network charges across the three EDBs involved in this Northland RETA, but the network charges for any individual process heat customer will depend on their particular location and network assets they utilise. Further, the process heat user should gain an understanding of the degree to which the EDB's charges will reward the process heat user for enabling and using flexibility in their demand.
- **A clear process, timeframes and information required for obtaining network connection**[112] – These processes should have realistic timeframes and the nature of the information that each stage of the process will provide the process heat user, and the data and information network companies need from the process heat user at each stage (see below). The recommendation above regarding a connection feasibility information template should be explored as part of this.
- **How flexibility in their electricity consumption and/or the level of network security they desire could impact the cost of connecting them to the network** – Like network charges and loss factors, the degree to which Transpower and EDBs can be flexible with network security and therefore the extent of network upgrades required depends on the connection location.
- **How upgrade projects could be accelerated, e.g. through:**
  - Early and bulk procurement of critical long lead time equipment (items such as transformers, switchboards, cable, conductors etc).
  - Consideration of expedited delivery (often suppliers will expedite for a premium or offer air freight options).
  - Paralleling design and build activities where possible to reduce durations.
  - Using commercial levers in contracts to expedite (i.e. delivery incentives or similar).

10.2.3 Information process heat organisations need to seek from electricity retailers

- **What tariffs they offer which lock in a fixed set of prices over multiple years** – This avoids process heat organisations being exposed to unexpected price rises.
- **What tariffs they are offering that reward process heat organisations for using flexibility in their electricity consumption** – While retailers will be able to provide tiered pricing (e.g. different prices for peak periods vs off-peak periods), they should be developing more sophisticated arrangements which can lower their wholesale costs, the benefits of which should be shared with organisations who provide them flexibility. This should include tariffs which give the process heat user more exposure to the underlying wholesale price, but retailers need to explain the nature of the risks of operating under such a tariff.

142 Transpower's web-based guide to the connection process is a good example. See https://www.transpower.co.nz/connect-grid/our-connection-process.

10.2.4 Information process heat users need to provide retailers, EDBs and (if relevant) Transpower

To obtain good advice, process heat users need to develop and share a good understanding of:

- The nature of their electricity demand over time (baseload and varying components), especially what time of day and time of year their demand is likely to reach its maximum level.
- The flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice, in response to system or market conditions.
- The level of security they need as part of their manufacturing process, including their tolerance for interruption.
- Any spare capacity the process heat user has onsite.

10.2.5 The need for electricity industry participants to encourage and enable flexibility

This RETA has highlighted some situations where costs could be significantly reduced if process heat users enable flexibility. However, New Zealand is currently lagging other electricity jurisdictions (e.g. the United Kingdom) in establishing a mature set of arrangements where electricity consumers can, if they wish, provide their consumption flexibility to electricity industry participants, and share in the benefits that flexibility creates. This lowers the costs of electrifying new process heat.

The FlexForum has developed a 'Flexibility Plan' for New Zealand, endorsed by MBIE, drawing on the expertise of over 20 members across a wide spectrum of the electricity and technology industries. The Flexibility Plan outlines 34 practical, scalable, and least-regrets steps that help households, businesses and communities maximise the benefits from the flexibility inherent in their electricity consumption.

Part of these benefits stem from the wholesale market, which creates the wholesale prices used to calculate electricity purchase costs incurred by retailers and large consumers who connect directly to the national grid. A future electricity system, with a higher penetration of renewables, will experience greater benefit from demand-side flexibility. It is likely that the retail market will evolve to reward customers who are able to respond dynamically. This does not necessarily imply that customers need to be fully exposed to wholesale prices. Customers may be able to remain on a stable retail contract, but one that has a lower tariff as a quid pro quo for assigning some degree of control over demand to an intermediary.

Practically speaking, this means that process heat users who are considering electrification should take into account:

- If there is flexibility in network security, process heat users should consider the degree to which their own loads could be modified (e.g. time-shifted through use of hot water storage) in order to accommodate network constraints, and/or quickly interrupted in the event a failure of a network component occurred.

- In principle, there are potentially significant benefits in having flexibility in their electricity demand (e.g. through maintaining a backup fuel/boiler system) that can respond to extended periods of electricity market stress (e.g. resulting from prolonged periods of low hydro inflows, sunshine or wind). That said, there are a number of logistical matters that would have to be considered to implement this, which EECA has not analysed.

For process heat users to be able to assess the benefits of process flexibility, they will need an improved level of information from electricity industry participants. EECA recommends better and more transparent information be published by EDBs, retailers, and the FlexForum about the benefits to process heat users from enabling flexibility in consumption, and the types of commercial arrangements (between electricity consumers and retailers/EDBs) that should exist to provide these benefits[113].

10.3 Pathways – insights and recommendations

The pathways provided in this report illustrated how different assumptions about how and when process heat organisations make decarbonisation decisions can impact the resources and networks that provide the fuels.

While the pathways have their limitations, and EECA will continue to enhance these in future RETAs (e.g. through more sensitivity analysis), they have illustrated the uncertainty faced by biomass and electricity suppliers. A lot of this uncertainty relates to the timing of decarbonisation decisions by the RETA organisations, and thus speaks to the pace of demand growth. Specifically:

- Some pathways saw sufficient growth in the near term that could result in progress being slowed by supply availability (biomass resources or network capacity). Given the likely lead times of bringing new biomass resources and/or network capacity to market, it suggests that **planning by forest owners, aggregators, and network companies needs to begin immediately, including the types of information sharing highlighted above.**
- The pathways highlighted that the extent to which process heat users are aware of, and incorporate, expectations of future carbon price trajectories into their decision making will have a significant effect of investment timing. Rigorous, publicly available long-term scenarios of carbon prices, and guidance for how process heat organisations can incorporate these into investment decisions, appears scant. Ministries such as **Ministry for the Environment need to work with reputable organisations to develop scenario-based forecasts of future carbon prices that decarbonising organisations can incorporate into their business cases.**

Other than public EV charging infrastructure, the pathways do not incorporate the potential for the growth in bioenergy and electricity for transport to compete with process heat. EECA will continue to develop the analysis to incorporate this in future analyses.

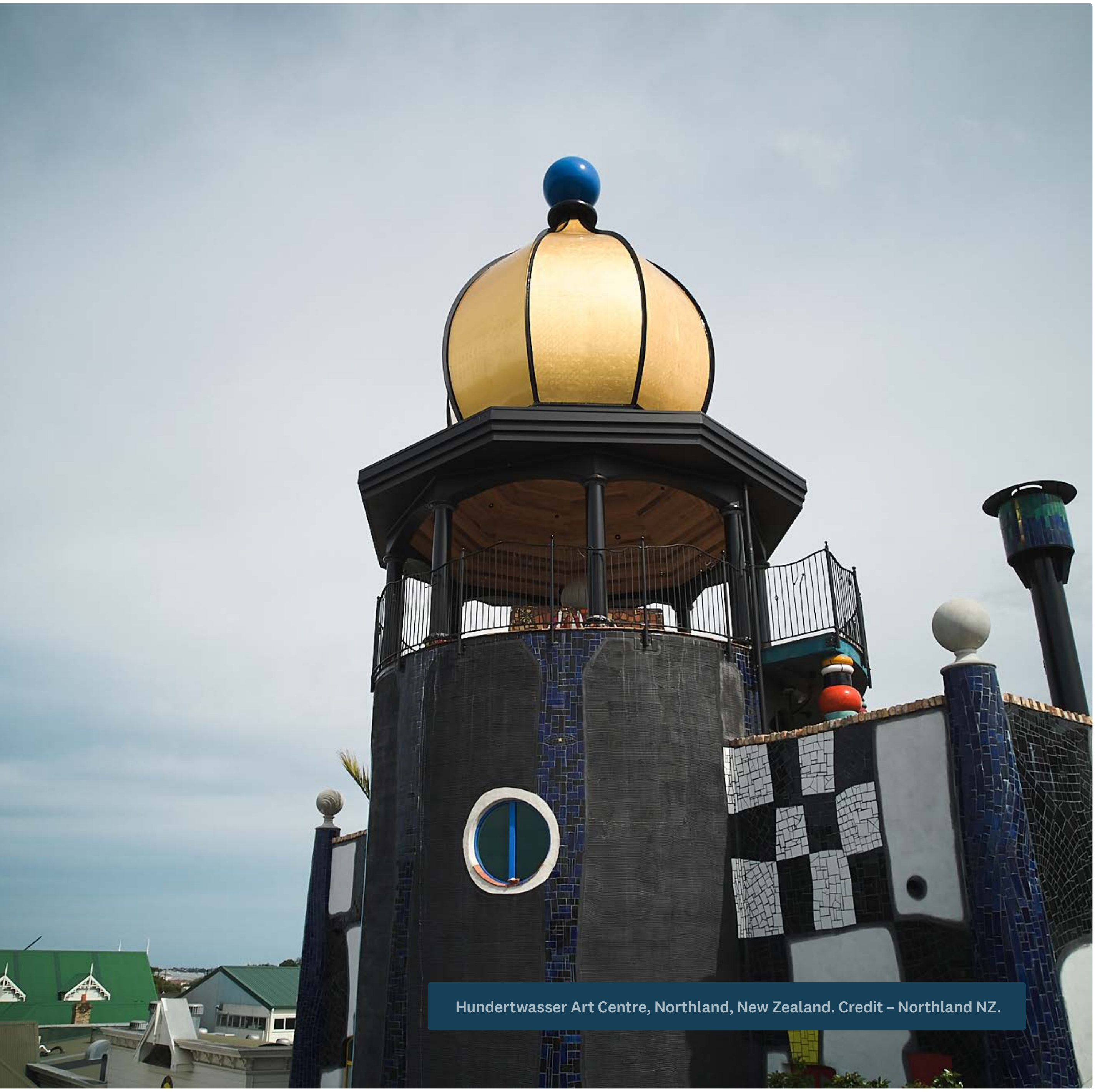
113 We note that, in its recent "Price discovery in a renewables based electricity system – options paper" the Electricity Authority's Market Development Advisory Group has included a preferred option C13 that recommends "Provide info to help large users with upcoming DSF investment decisions". See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf, page 64.

10.4 Summary of recommendations

In summary, our recommendations are:

- **More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the 'integrated model' of cost recovery, outlined above, achieve the best outcomes in terms of recovery cost and volumes.**
- **Mechanisms should be investigated and established to help suppliers and consumers to see biomass prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.**
- **National guidance or standards should be developed, based on international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**
- **EDBs should develop and publish clear processes for how they will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**
- **EDBs and process heat users should engage early to allow the EDB to develop options for how the process heat user's new demand can be accommodated, what the capital contributions and associated lines charges are for the process heat user, and any role for flexibility in the process heat user's demand. This allows both EDBs and process heat user to find the overall best investment option.**
- **To support this early engagement, EDBs should explore, in consultation with process heat users and EECA, the development of a 'connection feasibility information template' as an early step in the connection process. This template would include a section for process heat users to provide key information to EDBs, and a network section where EDBs provide high-level options for the connection of the process heat user's new demand. Information provided by EDBs would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer's flexibility.**
- **EDBs should ensure Transpower and other stakeholders (as necessary) – at an early stage – are aware of information relevant to their planning.**
- **Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**

- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.**
- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**



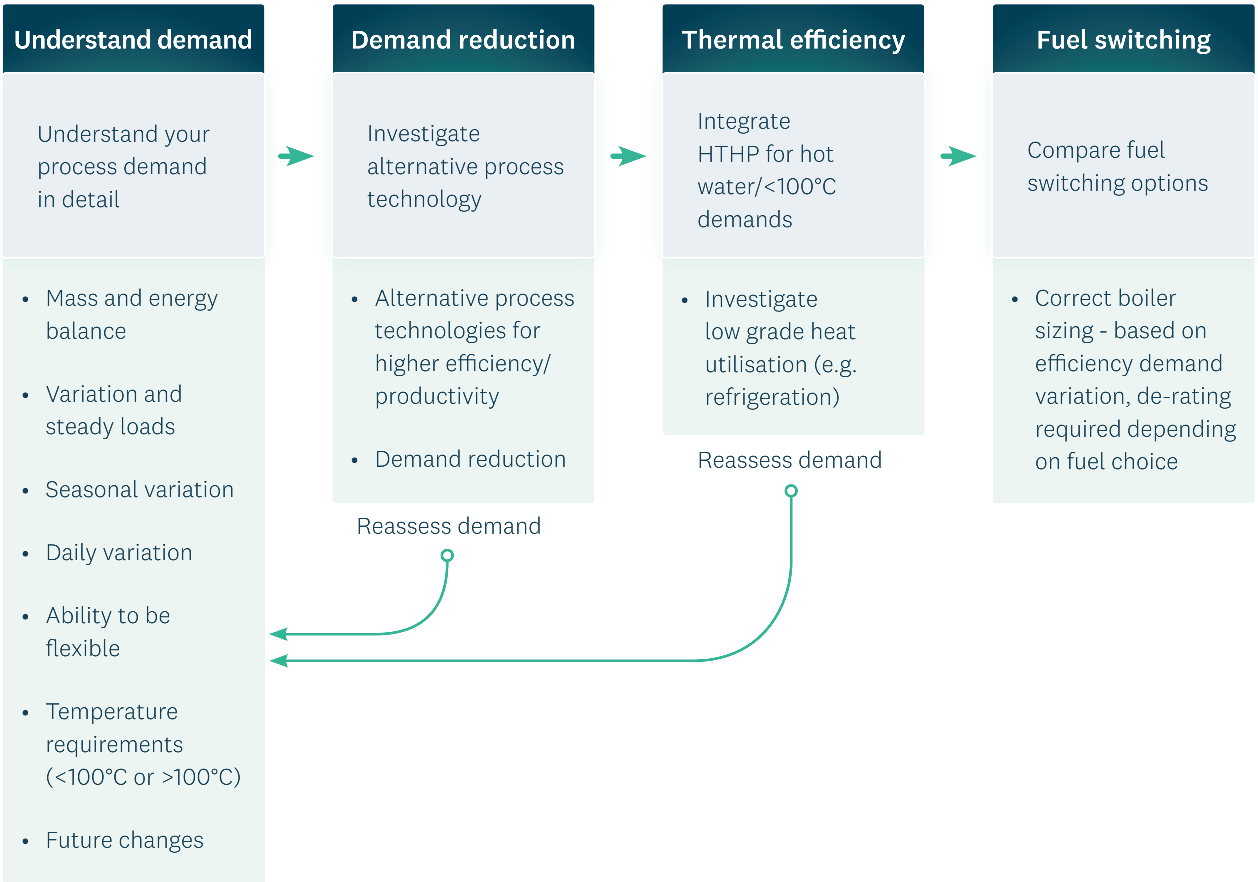
Hundertwasser Art Centre, Northland, New Zealand. Credit – Northland NZ.

11 Appendix A: Overview of the process heat decarbonisation process

For an individual process heat user, decarbonisation is a series of interconnected decisions. While the 'fuel' decision will usually be the most financially significant aspect of the project, a number of initial steps in the decision-making process can reduce energy consumption and emissions before the major fuel switch decision is made. These steps are usually commercially attractive in and of themselves, but also may result in reducing the capital cost associated with the fuel switching decision.

Figure 55 provides an overview of the main steps in the decarbonisation decision making process.

Figure 55 – Key steps in process heat decarbonisation projects. Source: EECA



As part of the fuel switching step above

Electricity

- Electrode boiler
- Network capacity increase required?
- Ability to flex demand to minimise cost
- Long-term electricity tariff
- Long-term carbon price

Biomass

- Age of boiler - conversion or new boiler?
- Long-term fuel supply and price – pellets, chip, hog
- Operational requirements for different fuels
- Fuel storage requirements for different fuels
- Long-term carbon price

11.1.1 Understanding heat demand

The importance of understanding the nature of a site's demand for process heat cannot be overstated. This includes an understanding of how it varies on an hourly, daily, weekly, and seasonal basis. A comprehensive understanding of heat requirements will underpin all subsequent decisions regarding efficiency, demand reduction, and fuel switching. An important aspect here, especially if electrification is to be considered properly, is the ability to be flexible in heat demand – can heat demand be interrupted or reduced for short periods of time (e.g. through utilising hot water storage). As will be discussed in Section 9.5, this flexibility can reduce the cost associated with any electricity network upgrades required to accommodate the project. It can also mean a financial reward for the process heat user through a variable ('time-of-use') electricity tariff. Similarly, this applies to biomass options as it may reduce the size of a boiler, which reduces the capital outlay required if a new boiler is contemplated.

There are four primary ways in which emissions can be reduced from the process heat projects covered by the Northland region RETA. For any given site, the four options below are not mutually exclusive and a number of options could be executed. Some of the options below are precursors for others – for example, to minimise the cost of a new boiler, demand reduction projects should precede commitment to the new boiler size.

11.1.2 Demand reduction and efficiency through heat recovery

Demand reduction includes projects such as heat recovery, temperature optimisation, equipment replacement, thermal insulation, and water flow reduction. These projects often have lower capital costs than fuel switching, providing a good return on investment and marginal abatement cost. The ability for a site to reduce demand is specific to its operations, so sites within the same sector usually have similar project opportunities. Opportunities in the meat industry include UV sterilisation, heat recovery, washdown optimisation, and pipe insulation[114]. For the dairy sector, opportunities could include waste heat recovery (including through use of heat pumps), conversion to mechanical vapor recompression, or preheating boiler feed water. These are often the best actions when considering energy productivity and the best use of limited funding.

It is critical to understand the full potential of demand reduction and best integration. Tools such as pinch analysis could play a key role in utilising the demand reduction to its full potential.

[114] See https://www.eeca.govt.nz/insights/eeca-insights/international-tech-scan/

11.1.3 Fuel switching to biomass – boiler conversions or replacements

Large-scale conversion to biomass will most typically draw on wood as a source of bioenergy. Within that, there is a range of options where wood is used to generate heat in a boiler.

Two primary and interrelated decisions when switching to biomass are:

- Whether the existing boiler will be replaced with a new biomass specific boiler, or the existing boiler will be converted from a coal supply chain to a wood-based one. The decision to convert an existing boiler will depend on its type, age, and condition, and may require a particular type of biomass fuel.
- What type of fuel will be used – for example, wood pellets, chip, or hog.

These two decisions involve a range of technical and financial considerations:

- If the site is converting an existing coal boiler, it may be able to be retrofitted to burn wood pellets or chip as a fuel. If a new boiler is contemplated, wood pellets, chip and hog are potential fuels.
- Wood pellets are a higher quality fuel and are more expensive, while wood chip and hog are lower quality fuels, but are more easily produced. Wood pellets require substantially more processing than other wood fuels, and bioenergy processing plants (e.g. pellet production) will likely have minimum levels of scale to be economic and may take time to be developed in the region.
- EECA has not considered in detail the logistical and emissions impact of transporting biomass but notes that wood pellets will have lesser transport requirements due to their higher energy density.
- Wood fuel must have a moisture content as specified in the fuel supply contract according to the design of the boiler. Out of specification fuel may impact the performance of the boiler and the overall process.
- Hog fuel is cheaper than wood pellets and chip but may require greater modification of existing storage and handling facilities which have been designed around coal. Due to the lower energy density of hog fuel compared to coal, more space (and likely a higher number of deliveries) is required to store it onsite.
- The available space on site is also important. Biomass fuel should be kept dry so larger, covered, storage facilities may be required compared to existing coal storage.

Fonterra, Auckland, New Zealand.

11.1.4 Fuel switching – electrification through high temperature heat pumps for <100°C requirements

Significant improvements in thermal efficiency can be achieved through the installation of high temperature heat pumps (HTHPs)[115]. As a result of their high efficiency, opportunities to use HTHPs where heat requirements are lower than 100°C are highly likely to be economically preferable to existing sources. These projects vary from site to site, but can provide heating for process water, potable water on industrial sites or HVAC on commercial sites.

Where a site has a range of heat requirements, heat pump projects should generally be considered prior to fuel switching as existing site heat can be utilised to decrease the required capacity of the new boiler. Depending on the site operations, a coefficient of performance (CoP) of three to five can typically be achieved[116]. While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat[117] have the potential to decarbonise much of New Zealand's industry within the 15 year timeframe contemplated by EECA's RETA decarbonisation pathways for the Northland region (outlined in Section 7).

11.1.5 Fuel switching – electrification through electrode boilers

Electrification sees electrode (or similar) boilers installed to generate heat. Compared to biomass boilers, electric boilers generally have a lower capital (purchase and installation) cost, but grid-sourced electricity is more expensive than biomass as a fuel at the current time. Operationally these boilers are ~25% more efficient than biomass, with highly flexible output and low maintenance costs[118].

A key consideration when assessing electrification projects is whether the increase in electricity demand from the site requires upgrades to the local or regional electricity network. The potential cost of such upgrades is considered in Section 9.

Finally, and as indicated above, while electrode boilers are more efficient, the electricity price is likely to be higher (on a $ per unit of energy basis) than biomass. However, electricity retailers can structure prices in a way that rewards the heat user for shifting its demand (to the extent possible) to periods where the electricity price is lower. This use of flexibility may also lower the cost of any electricity network upgrades triggered by the electrification of the process heat. This point is discussed more in Section 9.5.

115 See EECA's industrial heat pump fact sheet at https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat/

116 This means that one unit of electricity consumption can generate 3-5 units of heat. Heat pump systems coupled to refrigeration systems can achieve Coefficient of Performance (COPs) of 8 or more. Mechanical vapour recompression (MVR) technology can achieve significantly higher COP again.

117 Fonterra is planning to trial these heat pumps. See https://www.nzherald.co.nz/business/fonterra-could-build-giant-heat-pumps-for-factories-as-1-billion-dollar-sustainability-drive-continues/LTIMLRIC2VGSVOBXTXYYHJZRGE/

118 See https://genless.govt.nz/assets/Business-Resources/Electrode-electric-resistance-steam-generators-hot-water-heaters-for-low-carbon-process-heating.pdf

NZ Sugar, Auckland, New Zealand.

12 Appendix B: Sources, assumptions and methodologies used to calculate MAC values

12.1.1 Sources and assumptions

The modelling that sits behind the simulated pathways relies on an array of assumptions about the decisions individual organisations will make. Some of these relate to the individual characteristics of each process heat organisation in the Northland RETA, other estimates use the costs produced in Section 8 and 9 below.

Where possible we have used actual data for this analysis and the main sources of data include:

- Energy Transition Accelerators (ETAs)
- Energy audits
- Feasibility studies
- Discussions with specific sites
- Published funding applications
- Process Heat Regional Demand Database
- School coal boiler replacement assessments
- Online articles

The emissions profiles and reduction opportunities of all the major sites have been covered off using these sources, covering most emissions from the Northland RETA sites.

However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made. We outline this data below.

Demand reduction and low temperature heat opportunities

For demand reduction and low temperature heat (<100°C) opportunities, if ETA data is unavailable, the information in Table 15 is used:

Table 15 – Assumptions regarding heat pump hot water and demand reduction opportunities where ETA information unavailable. Source: DETA

Sector	Sub-sector	Proportion of total heat demand < 100°C	Peak demand reduction (%)
Dairy	Dairy	11%	11%
Industrial	Wood	10%	10%
Commercial	Buildings	10%	10%
Industrial	Meat	18%	18%
Industrial	Other industrial	25%	25%
Commercial	Schools	10%	10%

The following general rules have also been applied to each site, which reflect the decarbonisation decision making process outlined in Section 7.3:

- Demand reduction or efficiency projects are assumed to proceed, and will proceed first, so that boiler sizing decisions are based off the post-efficiency/demand reduction requirements[119].
- If a site only demands hot water at less than 100°C, there is the potential to replace the entire boiler load with heat pumps (depending on opportunities for heat recovery on site). If a site contains both <100°C water and >100°C heat requirements, a mixed approach may be adopted, using heat pumps for the hot water demands and a boiler conversion or replacement for higher temperature needs.

119 As a result, the total boiler demand from sites post-fuel switching decisions is lower than the demand implied from the process heat regional demand database.

Heat delivery efficiency

While information on the current consumption of fossil fuels is available, investment in new process heat technology will invariably lead to increased efficiency and thus a reduction in the energy required to deliver the required heat. Where ETA information is not available, we used the parameters in Table 16 to represent the efficiency of the new process heat equipment.

Table 16 – Assumed efficiency of new process heat technology, where ETA information is unavailable. Source: EECA

Existing boiler efficiency	78%
New boiler efficiency	80% (biomass) 99% (electricity)
Heat pump efficiency	400%

12.1.2 Our methodology for simulating commercially driven decisions

As outlined above, some of our pathways make simplifying assumptions about process heat user decarbonisation decisions. Other pathways seek to reflect more realistic, commercially driven decisions by process heat users. Here, we focus on how we simulate these commercial pathways.

There are a range of factors organisations face when deciding when to invest in decarbonisation, and which fuel to choose. These factors will invariably include the financial cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing or consumer expectations.

However, the softer factors are harder to model quantitatively. As a result, the methodology used here focuses on the financial components of the investment decision that can be modelled with available data. To a large extent, these are the factors relating to efficiencies and costs listed above, as well as known information about the current annual consumption of heat at each of the RETA sites.

Our simulated 'optimal' decision making framework presumes that the decision regarding which fuel to switch to, and when, is purely about the change in capital and operating expenditure arising from the project, using the information outlined above. Using discounted cashflows analysis, at an appropriate discount rate, we can determine the 'net present value' (NPV) of the combination of up-front capital costs and changes in ongoing operational costs (including the cost reduction from not consuming fossil fuels), tailored to each type of technology (heat pump or boiler) and fuel (electricity or biomass). We then assume that the process heat user would choose the option with the best (highest) NPV.

For an indicative set of parameters, Figure 56 illustrates the NPV for three different fuel choices.

Figure 56 – Illustrative NPV for different heat technology options. Source: EECA

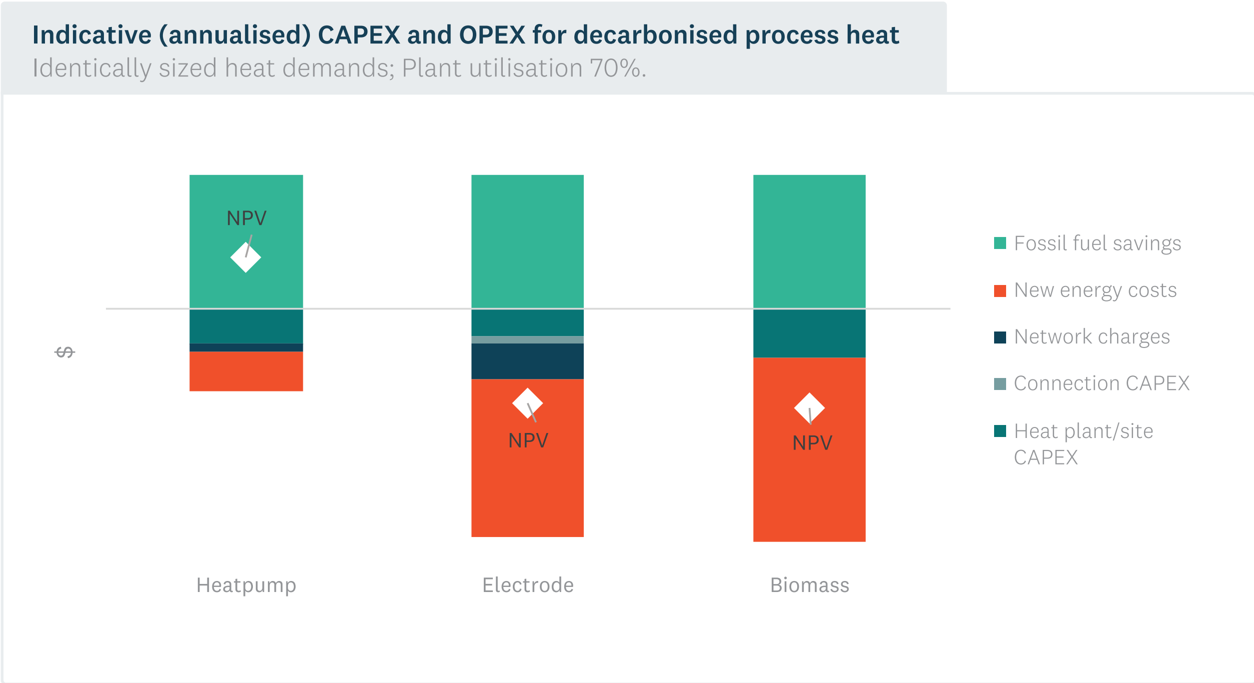


Figure 56 shows that, if the process heat site is using low temperature (<100°C) heat, a heat pump has the highest NPV. In fact, it would have a positive NPV, as the cost of the heat pump option would be more than offset by the savings in fossil fuels. This is a result of the significantly higher efficiency of the heat pump, compared to other options.

For heat requirements over 100°C, the NPV for both electricity and biomass is negative at current fossil fuel prices. As carbon prices rise, the price of fossil fuels will increase, as will the savings from switching to low emissions fuel. An increasing carbon price will eventually result in the NPV becoming positive for several sites – we explore this further below.

Figure 56 also illustrates the relative cost components of electricity vs biomass investments:

- The variable costs of fuel are lower for electricity (retail charges) than biomass. In this illustrative case, this is principally due to the boiler efficiencies – an electrode boiler is ~25% more efficient than a biomass boiler.
- While the capital costs of an electrode boiler are assumed to be around half that of a new biomass boiler, electricity also faces upfront capital costs (associated with upgrades to the network) as well as annual network charges which are a function of connection capacity and peak demand. These network charges can potentially be reduced by reducing electricity consumption during peak periods, as outlined later.

The impact of fixed costs on the economics of an investment is heavily influenced by the utilisation of the boiler. Because fixed costs don't change with the usage of the plant, the economics of high utilisation plant (such as dairy factories) will generally be better than low utilisation plant (for example, schools). This is why the economics of low utilisation process heat sites tend to favour biomass – in a range of situations, the fixed costs are lower for biomass, due to the absence of network upgrade costs and charges.

To illustrate this point, Figure 57 illustrates the relative economics with the same parameters as Figure 56, except we have lowered the utilisation of the plant from 70% above, to 20%.

Figure 57 – Illustrative NPV for different heat technology options, low (20%) utilisation. Source: EECA

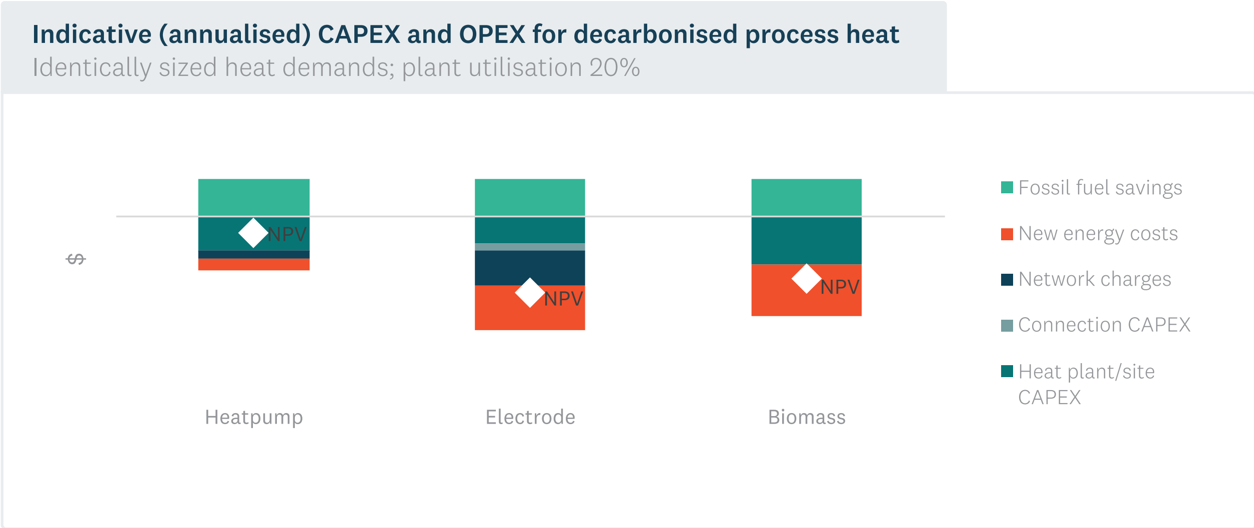


Figure 57 shows that the economics now favour biomass (if the process heat user requires heat greater than 100°C). This is because the consumption-related costs (retail electricity or biomass) have reduced, but the fixed network costs for both options remain the same. Since the biomass had lower fixed costs, it now outperforms electricity.

12.1.3 Comparing economics from a decarbonisation perspective

Whilst comparing NPVs is a useful commercial approach, the example above highlighted that an important factor is the impact of an increasing carbon price on the cost of continuing to use fossil fuels for process heat. Although today the carbon price may not be sufficiently high to result in a positive commercial outcome from decarbonisation, the carbon price is expected to increase in the future. At some point, projects that are currently uneconomic are likely to become economic. At this point, the cost of continuing to use fossil fuels (effectively the green bars in Figure 56 and Figure 57) will exceed the cost associated with reducing emissions (via investment in electricity or biomass).

Understanding when this point might occur requires us to calculate a 'levelised cost of emissions reduction' for each project and fuel type (biomass or electricity), also known as a 'marginal abatement cost' (MAC).

MACs are just another way of viewing the NPV of the project, except that it is 'normalised' by the tonnes of emissions reduced by the investment. MACs are calculated as follows:

$$MAC\left({}^{\$}/_{CO_2e}\right) = \frac{NPV(Project\ Costs\ (\$))}{NPV(emissions\ reduced\ (tCO_2e))}$$

The NPV in the formula differs in one major respect from that illustrated in Figure 56 and Figure 57 above – it must not include the future estimated carbon price. As a result, it provides the underlying average cost of reducing emissions as though there was no carbon price. This can then be correctly compared with the current and future carbon price.

MAC values can then support a process heat user's investment decision in two ways:

- **Fuel choice –** As discussed above, since it incorporates the underlying NPV of the project, the MAC gives a relative ranking of the options (heat pump, electrode, or biomass boiler), just expressed per-tonne of CO_2e. A high MAC value suggests that project's cost of reducing a tonne of carbon dioxide is higher than a project with a low MAC value.
- **Investment timing –** Having determined the option with the lowest MAC, it then can be used as an indication of the best time to invest in decarbonisation by comparing it with likely carbon prices. Ultimately, carbon prices flow through to the fossil fuels used by the RETA organisations via the price of the fuels they use. If the national carbon price is expected to be higher than the MAC value (the 'cost of carbon reduction'), then the organisation will have lower costs in the future by investing in decarbonisation and reducing its exposure to future carbon prices.

New Zealand's carbon price is set primarily through the Emissions Trading Scheme (ETS); however, the quarterly carbon auctions which determine this price only reflect the *current* supply of, and demand for NZUs. Many RETA businesses will be aware of the impact of the current carbon price on the price of coal -today.

Comparing the optimal fuel's MAC value against today's carbon price doesn't fully capture what the business will be paying for coal, diesel, and LPG in the future. This is especially important when considering investments in boilers – that will avoid the cost of carbon – that have a life of 20 years (or more). Put another way, decarbonising process heat doesn't just avoid today's cost of carbon, it avoids it over the life of the investment.

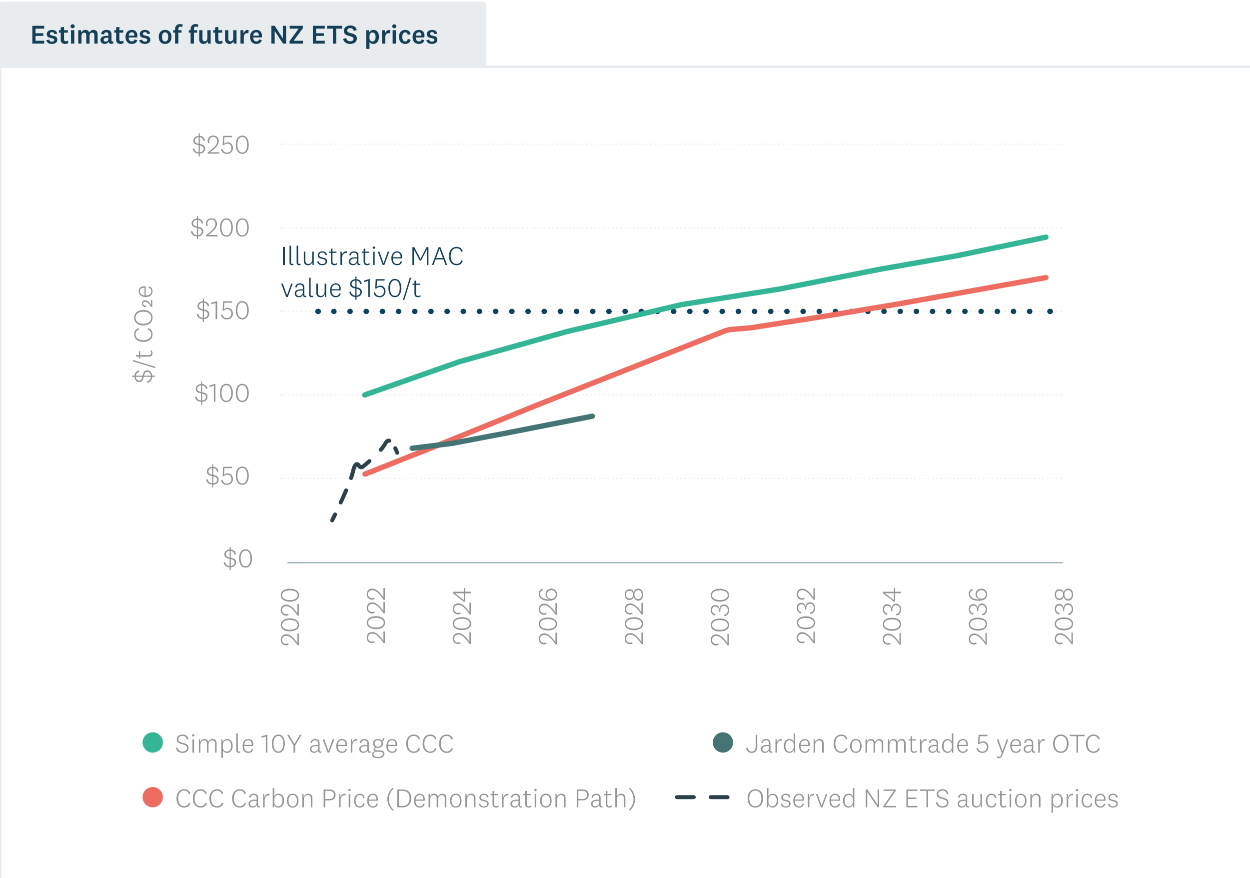
If the carbon price was expected to rise, then the investment would be more attractive than if only today's price of carbon was used. The challenge for many organisations is how to form a view on the carbon price (andits impact on the business) *in the future*[120], should it continue to consume fossil fuels. Unfortunately, there are few publicly available forecasts of carbon prices through which a process heat user can get confidence that carbon prices will reach a level which makes the investment economic. Even if these forecasts were available, it is entirely understandable that an investor might 'wait and see' if the increases materialise, before committing investment.

A view on future carbon prices can be informed by the Climate Change Commission's modelling of emissions values in its 'Demonstration Path' scenario[121] (represented as the red solid line in Figure 58). Whether or not ETS prices follow that CCC pathway depends largely on whether government policies and resulting decisions by consumers and businesses are aligned with the 'emissions budgets' recommended by the CCC.

120 To some extent, this is no different to an organisation considering the future prices of any of their major input costs, except that the carbon price is often already packaged into the cost of the fossil fuel they consume (coal, gas or diesel) and may not be itemised separately by the fuel supplier.

121 Technically, emissions values are different from market carbon prices, and they represent the cost of reducing the last ton of emissions in the economy at a certain point in time, given a certain decarbonisation ambition. In other words, CCC's values are a series of modelled 'shadow' carbon prices (to 2050) that is consistent with New Zealand meeting its aspirations around carbon reduction. See https://www.climatecommission.govt.nz/news/dive-into-the-data-for-our-proposed-path-to-2035/

Figure 58 – Future views of carbon prices.



Recognising that it is the carbon prices over the lifetime of the investment that represent the carbon costs that the organisation will face, we have used the 10-year future average of the CCC's demonstration pathway. This is the green solid line in Figure 58.

The black dashed line shows the outcomes of actual NZ ETS auctions (held each quarter). These are the result of the bids by organisations that need to purchase NZUs, cleared against the volumes made available by the government (at reserve prices).

We have also included one broker's clearing prices of NZU contracts being traded up to five years in the future – this offers another view of the market's expectation of carbon prices, as at March 2023[122]. It will likely include the effect of the failed NZ ETS auctions that took place in March and June.

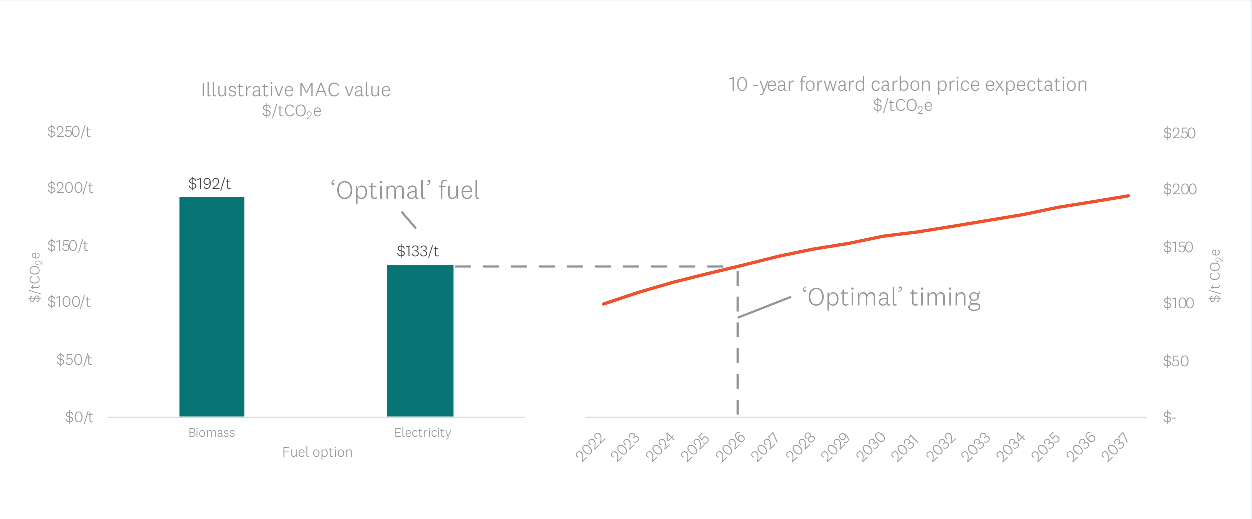
Different future views on carbon prices, and different ways of using those views, could have quite different impacts on the timing of decarbonisation projects proceeding. Assuming that the CCC Demonstration pathway is a good forecast of carbon prices, Figure 18 shows that a project with a $150/t MAC value would not be committed until 2033 if the decision maker used the current carbon price to trigger the decision, but would proceed earlier – in 2028 – if they used the simple average of the next 10 years of carbon prices implied by the CCC Demonstration path.

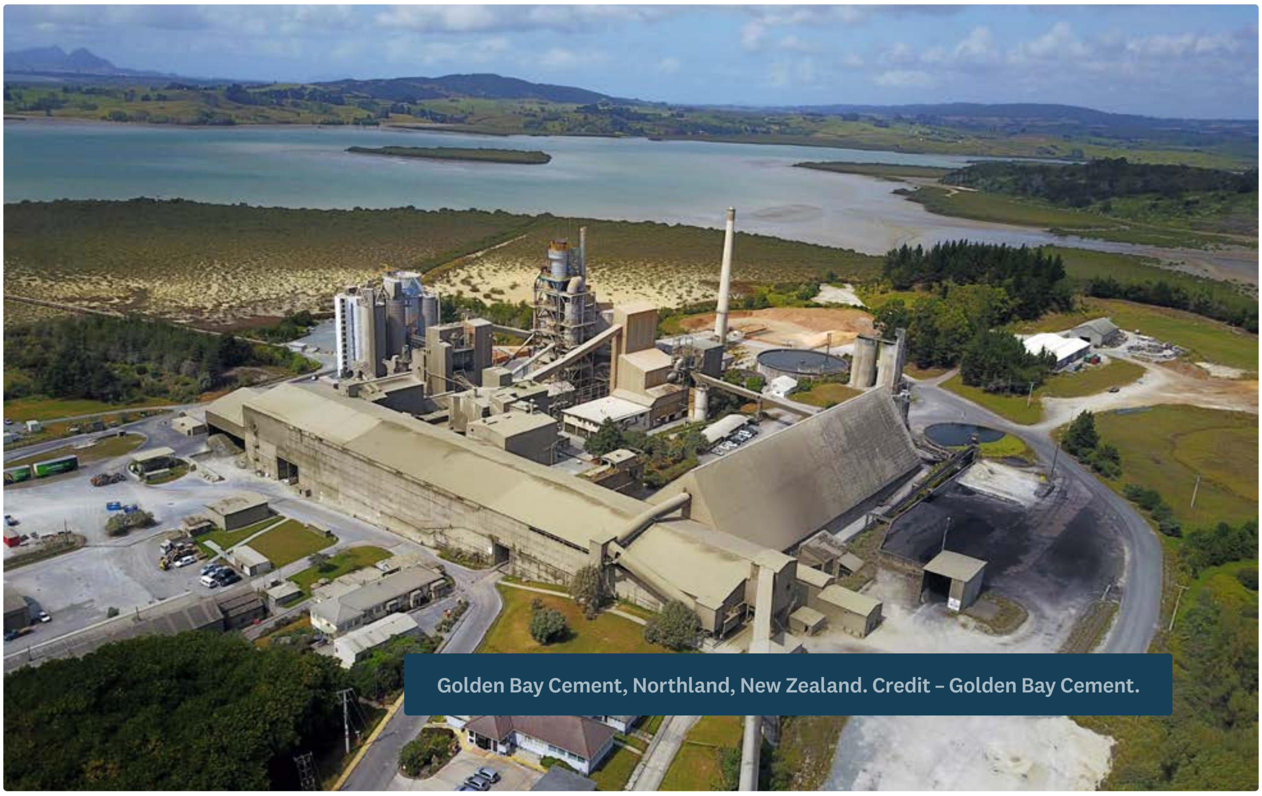
[122] Because NZUs can be purchased today and stockpiled/held for the future, these forward prices contain very limited information about future carbon prices other than the cost of carry (i.e. working capital/interest rates. If, however, the only way to meet NZU obligations in, say, 2026 was to purchase 2026 vintage NZUs, then forward contracts would have significant signalling value.

For this report, we have chosen to use the 10-year forward average of the CCC's demonstration path to determine the investment timing, as we believe this is a better reflection of the actual financial impact of *future* carbon prices on a long-term investment than just using the solid red line in Figure 58.[123]

The overall framework for how we use MAC values to create the MAC Optimal pathway below is shown in Figure 59.

Figure 59 – Illustration of how MAC's are used to determine optimal decision making. Source: EECA





Golden Bay Cement, Northland, New Zealand. Credit – Golden Bay Cement.

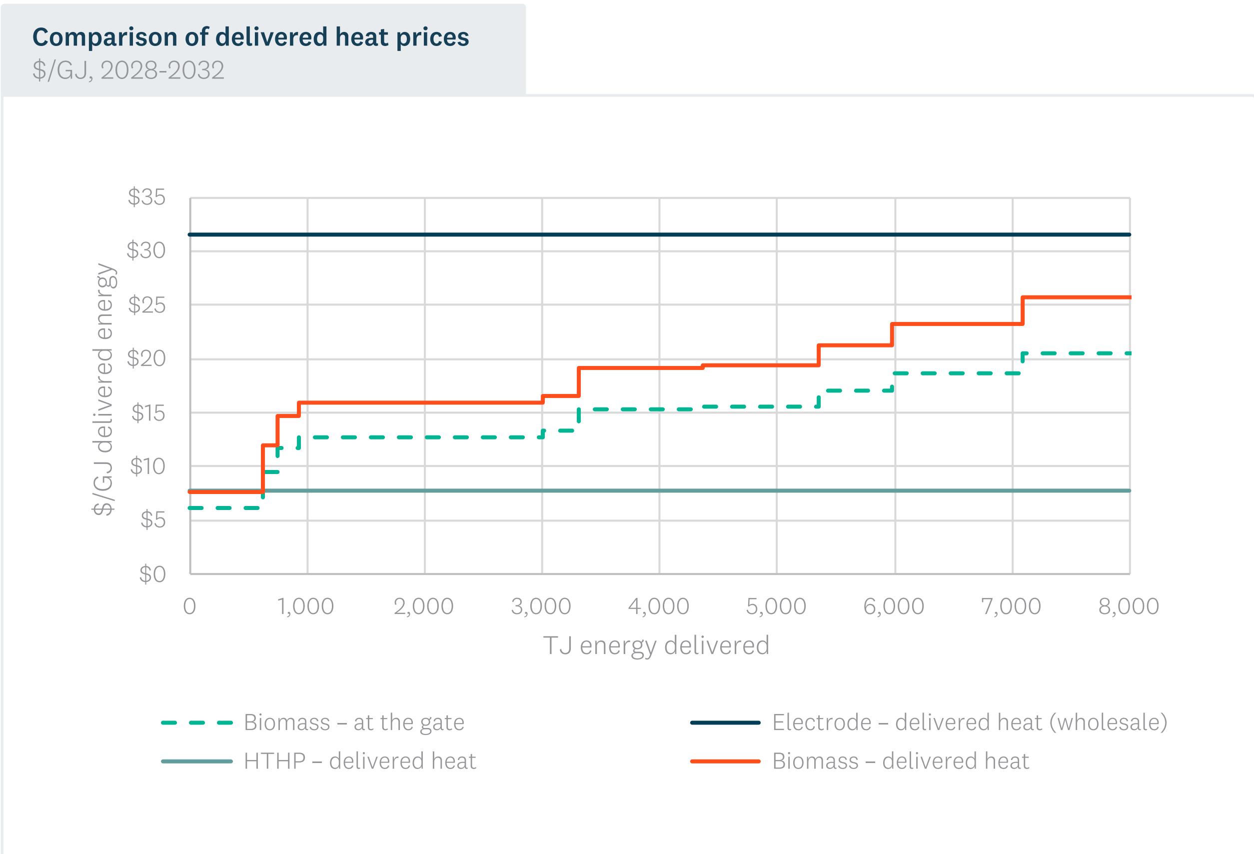
123 This is not the only correct way to determine investment timing. There are a range of other frameworks for decision making, which could result in earlier or later investment timing.

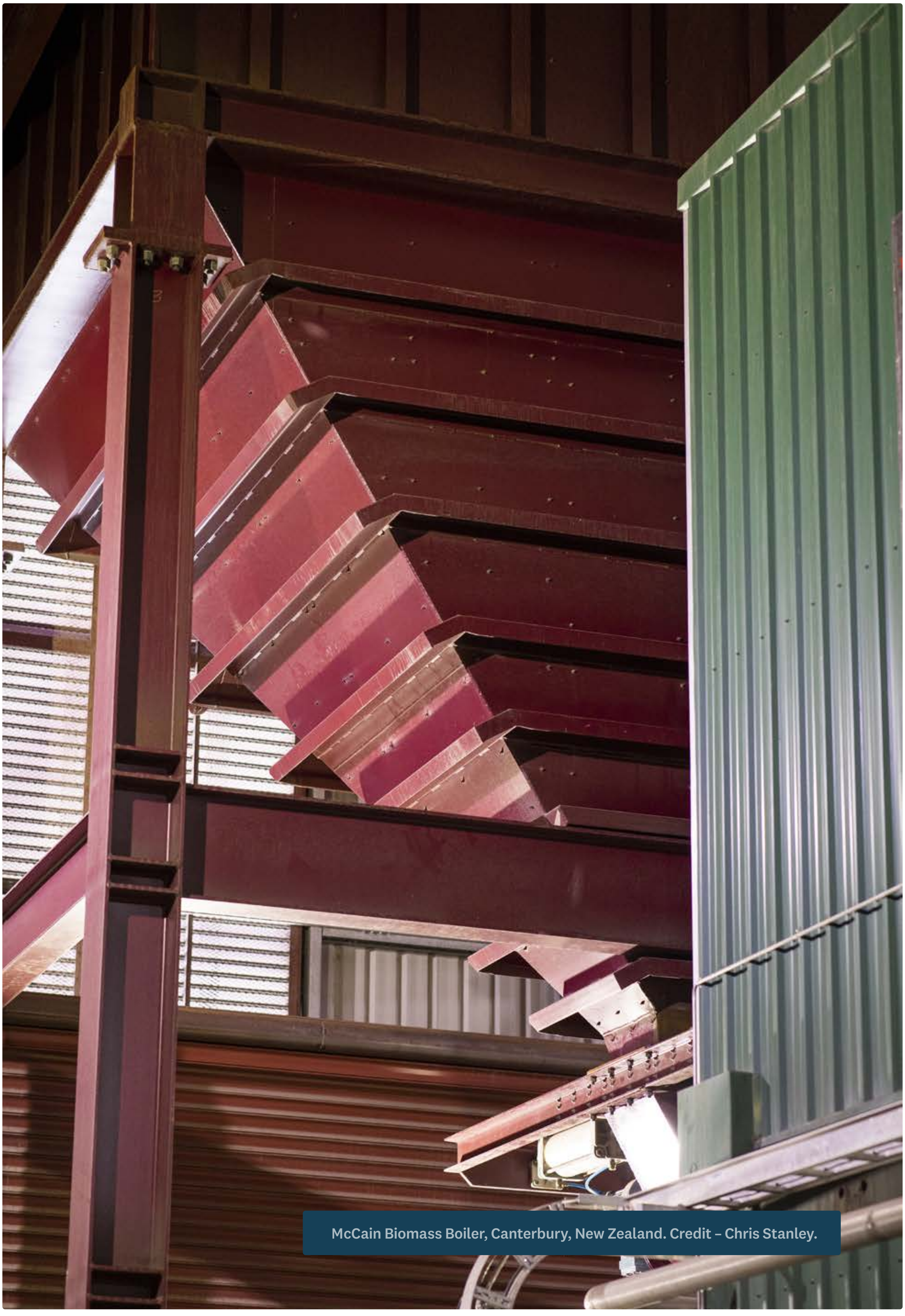
12.1.4 The impact of boiler efficiency on the 'cost of heat'

The MAC analysis implicitly trades off all the costs – capital, operating and fuel – to provide a single analysis of the lowest-cost fuel (from an emissions reduction perspective). This (necessarily) incorporates the different efficiencies of the boiler technologies chosen. For sites that can contemplate both biomass and electricity as fuel switching options, the delivered cost of biomass (to the 'gate' of the site) cannot be directly compared with the delivered cost of electricity (or any other fuel) without accounting for the fact that, biomass boilers have approximately 80% efficiency, whereas electrode boilers have close to 99% efficiency. On the same basis, heat pumps have coefficients of performance that are four or higher. The cost per unit of heat received by the process is therefore different from the cost per unit of the energy delivered to site.

In Figure 60, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 8.7 (for a biomass decision) and the electricity price path from Section 9.2 (for an electrode boiler, and heat pump decision). Note that these are only the variable costs of the fuel, and do not incorporate the fixed costs associated with different investment decisions (which are considered with the MAC calculation). The biomass price does not account for any margin that suppliers may seek on the various bioenergy resources, which we expect would add $3/GJ to the biomass figure, nor secondary transport from the hub to a process heat user's site (assumed to be $3/GJ).

Figure 60 – Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: Ahikā, Forme, EnergyLink, EECA.





McCain Biomass Boiler, Canterbury, New Zealand. Credit – Chris Stanley.

13 Appendix C: Electricity supply and infrastructure explanatory information

The following sections provide detailed information on technical and complex aspects of electricity supply and infrastructure referred to in Section 9.0 of this report.

13.1 Pricing

13.1.1 Energy pricing – wholesale

As noted in Section 9.2 the generation or 'wholesale' cost of electricity is the result of electricity prices that arise from a market that clears supply and demand every half hour of the year. In order to derive a forecast of future retail electricity prices that can be used to assess the economics of electrification projects, ideally New Zealand needs a model that reflects the likely interaction of supply and demand, and therefore prices, in the wholesale market.

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. EnergyLink's model simulates the interaction of wholesale electricity supply and demand, and produces wholesale market prices, in a way that closely resembles the mechanics of the actual half hourly market. This includes the way the New Zealand electricity market incorporates transmission losses into the wholesale price observed at each of the ~250 locations (GXPs or GIPs[124]) around the country where power is traded and reconciled. Finally, it also includes the impact of varying inflows into hydro reservoirs, which remains critical given New Zealand's reliance on hydro generation (~55% of total generation) will remain for some time yet[125].

However, to produce these prices over a multi-decadal timeframe, assumptions need to be formed about the future wholesale supply of, and demand for, electricity over this period. Given the significant uncertainty facing the electricity industry presently, EnergyLink developed three scenarios of supply and demand, including fuel costs, carbon costs and investment costs associated with new supply (as shown in section 11.1.2.1).

124 Grid Exit Points (where electricity leaves the grid) and Grid Injection Points (where electricity enters the grid from power stations).

125 There is some evidence from climate analyses that, at least on average, inflow patterns into the major hydro storage lakes (Lakes Tekapo and Pukaki, which represent ~70% of New Zealand's controllable storage) will change over the coming decades. The principal effect is that less precipitation will fall as snow as the globe warms, which has the effect of increasing winter inflows into these alpine lakes. EnergyLink have not included these effects in the scenarios produced for this project.

13.1.2 Energy pricing – retail

Most large users of power do not elect to face the half-hourly varying wholesale price, and instead prefer the stability of multi-year retail contracts that contain a schedule of fixed prices, that each apply to different months, times of week and times of day[126]. The three wholesale price scenarios were adjusted to reflect the observed difference between the wholesale price of power, and how large user retail contracts are typically priced. This is an approximation based on historical evidence but should be a plausible guide (based on historical trends) to what customer should expect if it sought this type of retail contract. Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options.

The retail electricity prices scenarios produced by EnergyLink are relevant to process heat users, reflecting what would be expected from a retailer that was pricing a large commercial contract. It is important to understand that:

- The Energylink price is only forecast for the generation and retail ('energy') component[127] of the customer's tariff, that is, they do not include network charges (use of the existing transmission and distribution network, which is in addition to the costs of any upgrades considered above) which will vary from customer to customer. The network component of the bill is discussed in Section 9.2.4 and 9.2.5.
- Energylink prices include the effects of high-voltage transmission losses to the nearest GXP in the Northland region, but do not include distribution network losses to the customer's premises. Loss factors are set by EDBs companies to account for distribution losses, and these loss factors are applied by retailers to the GXP-based price. In the case of Northland, distribution losses are varied across the two EDBs, with Top Energy's being very high in comparison to Northpower. This is likely due to the long and 'stringy' nature of Top Energy's network especially via the single circuit supply to the Far North, where the terrain is rugged and the area sparsely populated. The distribution losses for sites connecting at or below 11kV are around 1.05 for Northpower, and 1.12 for Top Energy[128].
- Energylink produce prices for four time 'blocks' each month – business day daytime, business day night-time, other day daytime and other day night-time. Different arrangements with a retailer may allow for different granularities of pricing and may also allow for the site to be rewarded for responding to, for example, high wholesale prices by shifting demand (see Section 9.5).

This is a relatively orthodox approach to modelling the electricity tariffs that process heat users may be presented with by their retailers. However, some electricity retailers are evolving their tariffs to provide incentives for large process heat consumers to convert to electricity, and these tariffs have begun to emerge in the New Zealand industry[129]. As part of this RETA analysis, we have incorporated currently available special offers for process heat decarbonisation to be representative of retail prices for the first 10 years of a fuel switching project, after which we revert to EnergyLink's forecasts.

[126] Common contracts are often referred to as '144 part' contracts, reflecting the fact that the prices are specific to 12 months, two-day types (weekday and other day) and six time periods within the day.

[127] This is generally the costs we have discussed above, relating to generation plus transmission losses and retailer margin, insofar as the latter is included in variable (c/kWh) charges. Some components of retailer margin may also be included in fixed daily charges from the retailer.

[128] EDBs publish network loss factors for different parts of the network, usually as part of their pricing schedule. An individual customer can find their loss factor by entering their ICP number (found on a recent power bill) in https://www.ea.govt.nz/consumers/your-power-data-in-your-hands/my-meter/ . The distribution loss factor for that site can then be found under the 'Network Pricing' section.

[129] For example, Meridian's process heat electrification programme pricing.

13.1.2.1 Scenarios considered

The three scenarios are characterised by assumptions that represent a central price scenario plus:

- **Low price scenario:** Assumptions that would lead to lower electricity prices compared with the Central scenario, through, for example, lower demand, lower fuel costs, or accelerated[130] build of new power stations.
- **High price scenario:** Assumptions that would lead to higher electricity prices than the Central scenario, for example, higher demand, higher fuel costs or more restrained investment in new power stations.

The three scenarios used are outlined in Table 17 below. More detail on these assumptions is available in EnergyLink's report[131].

Table 17 – Electricity market scenarios considered. Source: EnergyLink

Scenario driver	Central price scenario	Low price scenario	High price scenario
NZAS at Tiwai Pt	Remains	Closes in 2025	Remains
Demand growth[132]	46TWh by 2032; 63TWh by 2048	As for Central scenario but ~5TWh lower from Tiwai exit	50TWh by 2032, 70TWh by 2048
Coal price	USD85/t	USD70/t	>USD100/t
Gas price	Medium	Low	High
Initial Carbon price[133]	NZD75/t	NZD75/t	NZD75/t
Generation Investment behaviour[134]	Neutral	Aggressive	Lagged/Conservative
Generation disinvestment	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2033	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

130 There is a limit to which the market will pursue accelerated or restrained investment – one would consistently suppress prices while the other consistently raise prices. This eventually has a feedback loop on other investors' intentions in terms of the profitability of their investment, and the timing of their investment (to the extent they can secure financing). However, we believe the degree of acceleration implied by EnergyLink's assumptions is plausible.

131 EnergyLink (2022), 'Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program', May 2022.

132 EnergyLink did not provide sufficient data to perform a direct comparison, but their Low scenario appears slightly lower than the CCC's Demonstration Path (which included a Tiwai exit). EnergyLink's Central Estimate in 2032 looks ~3TWh lower than the CCC's 'Tiwai Stays' sensitivity.

133 Note that the impact of the cost of carbon on the electricity price reduces over time as the electricity supply chain decarbonises and wholesale electricity prices become less sensitive to the cost of electricity generation that has a carbon component.

134 Specifically, EnergyLink assume that a neutral approach would be an investor seeking to time construction such that target EBITDA is reached within two years of construction. A more aggressive approach would see investors build earlier (tolerating an undershoot of EBITDA by 10%), whereas a lagged approach would see investors delay construction to ensure 10% more than target EBITDA is achieved two years after construction.

EnergyLink also model the 'levelised cost of energy' (LCOE) associated with generation investment classes (e.g. wind, solar) into the future[135]. The degree to which these forecasts of LCOE affect investment are then a function of these costs, the way the projects are assumed to be financed, and the cost of debt.

Noting that the Low and High scenarios are not necessarily designed to be the most plausible storylines[136], but instead to apply assumptions that would deliberately lead to high and low-price outcomes. As with many scenario analyses that involve mathematical models, there is a tendency for these models to understate the true range of potential prices as they cannot incorporate all the real-world factors (including human decision making) that drive price. EnergyLink's scenarios provide information on what a range of price outcomes might look like. It is also important to note that the Low and High scenarios assume the variables in the table persist every year for 25 years. In reality, the market could periodically 'switch' from one scenario to another and remain there for a number of years.

The following assumption in EnergyLink's modelling are also relevant:

- The scenarios assume that the national electricity system reaches the Climate Change Commission's target of 95% renewable generation by 2030.
- The scenarios have not factored in the proposed pumped storage scheme at Lake Onslow. They do assume that the remaining thermal peaking plant can be switched (if deemed economic) to a low emissions fuel and has fuel storage large enough to support the system through extended periods of low inflows[137].
- EnergyLink apply different inflation assumptions to the various assumptions in the table above, each of which imply different rates of decline from its current level of 7% to a long-term rate of 2%.

135 "In real terms, the cost of building, owning, and operating new wind generation falls at rates calibrated against actual wind projects in New Zealand, with adjustments for the cost of financing projects. The cost of grid-scale solar farms also falls in real terms, but as there are no such projects in New Zealand, the rate at which costs fall is calculated from a combination of information that is in the public domain in New Zealand, along with data from overseas." EnergyLink, p 14, footnote 20

136 For example, in the Low Scenario, Tiwai is assumed to exit but other decarbonisation demand is also assumed to be muted. However, it is the Tiwai exit scenario that is mostly likely to accelerate initiatives to decarbonise, not least because the price of electricity will be suppressed for quite some period of time, making electrification attractive.

137 Studies into future electricity supply are also considering the emergence of 'dunkelflaute' conditions, which are extended periods of cloud and low wind. These periods, potentially of weeks, such as that observed in continental Europe in 2021, would be beyond the capability of lithium-ion batteries and would also benefit from the presence of flexible generation such as peakers.

13.1.3 Network charges – distribution

As noted in section 9.2.4, EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return. The total amount EDBs can earn is regulated by the Commerce Commission, while the way they charge (generally referred to as 'distribution pricing'[138]) is overseen by the Electricity Authority.

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'[139].

The difference in prices between EDBs can reflect a variety of characteristics of each network – their pricing methodologies (which determines how costs are allocated between domestic, commercial, and industrial consumers), the nature of their network (e.g. proportion of high-density urban environments versus sparse rural areas) and where they are in their investment cycle.

When considering a business case for an investment that will last many years, a very important factor is the potential changes in how EDBs might structure their prices, and the degree to which these charges will be reflected in retail electricity contracts.[140] The Electricity Authority is working with EDBs to move their pricing approaches, over time, towards more efficient pricing structures, with five focus areas:

- Planning for future congestion
- Avoiding first mover disadvantage for new/expanded connections
- Transmission pricing pass through (see below)
- Increased use of fixed charges
- Not applying use-based charges (e.g. Anytime Maximum Demand) to recover fixed costs

More detail is available on the Electricity Authority's website.[141]

138 By this we mean how they allocate their costs amongst different customer groups, what variables they use to charge customers (e.g., capacity, peak demand, volumetric consumption) and other principle-based oversight. For more information see https://www.ea.govt.nz/projects/all/distribution-pricing/

139 The 2023-24 pricing schedules and methodologies for each EDB can be found on their websites.

140 Having these charges passed directly through to the process heat customer is only one way to incentivise flexibility. Since retailers ultimately pay these charges to distributors, another way is for retailers to work with the process heat users to reduce demand at high price times, this reducing the retailer costs, and share this benefit with the process heat user in any number of ways.

141 See https://www.ea.govt.nz/projects/all/distribution-pricing

13.1.4 Network charges – transmission

Where a consumer connects directly to the grid, Transpower will charge this consumer directly. The rules governing how Transpower charges its customers (distributors, directly connected industrials and generators) are determined by the Electricity Authority. These rules – known as the 'Transmission Pricing Methodology' (TPM) – have been a contentious topic since Transpower was separated from ECNZ in the early 1990s. Over the past 10 years, the Electricity Authority has conducted a number of phases of consultation in an effort to create a more enduring TPM, less subject to litigation.

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These charges come into effect for the 2023/24 pricing year[142]. Alongside the new TPM, the Authority released guidelines for EDBs as to how to pass through the new transmission charges to their customers (which will include the majority of process heat users covered by this RETA)[143].

The TPM is incredibly complex, and it is not possible to present the methodology in any detail here. But it is materially different from the TPM that has been in place for a number of years. In order to help process heat users understand these changes, we provide below a commentary below on what the TPM is trying to achieve, and what that might mean for charges that are passed through by EDBs to process heat users. An outline of the TPM and more detail is provided below in Section 11.2.

13.1.5 Network security levels

While highly reliable, there is a small chance that components within electricity networks may fail. The conventional approach to maintaining supply to customers in a scenario of network failure is to consider the degree to which parts of the network have an in-built degree of redundancy in order to provide customers security of supply.

Like most infrastructure, electricity networks are sized to accommodate the very highest levels of expected demand ('peak demand'). In electricity, these peaks are often only a small number of hours per year and can occur at predictable times. Hence the overall level of 'secure capacity' is defined by the degree of redundancy that is available at peak times. At other times, more capacity is available. The level of secure capacity available to an individual site is a function of both:

- The available secure capacity at the point in time that the overall demand on the network reaches its highest level.
- The degree to which the site adds to that peak at the time it occurs (usually referred to as 'coincident demand').

142 A pricing year begins on 1st April for all network companies.

143 We note that these guidelines did not include direction as to how EDBs or retailers present the transmission charges on the customer's bill. Process heat users (and any other customers) may not see any detail about what component of their new bills relates to the new transmission charges, although we expect distributors and retailers will want to explain any material increases in the overall bill.

Generally N-1 is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population. However, on some more remote parts of Transpower's grid, the economic trade-off between N-1 and the cost to local consumers of the investment to accommodate demand growth may mean lower security is more efficient, and/or there are other ways to provide N-1 (see below) and better balance affordability.

The extent to which an EDB provides (or preserves, in the face of increasing demand) N-1 is a risk-based assessment which considers, amongst other things, the proportion of time that a particular part of the network would exceed N-1 capacity; the economic and risk profile of the existing customers; and the trade-off between the costs of extra capacity versus increased risk of interruption. For this reason, N-1 is often provided by EDBs in urban areas where there is high density of households and businesses. Approaches to determining where N-1 will or won't be provided are typically detailed in the EDB's asset management plans (available on their websites), and process heat users should engage with their EDB to determine how this applies to their site.

For the purposes of this report, Ergo determined the amount of spare capacity by using Transpower's prudent peak demand forecast[144] for the coming year (2023), rather than actual observed peak demand as inferred by Figure 55. The use of a prudent forecast recognizes that there are a range of variables that can determine what happens on a given day or time, such as weather and the decisions of individual consumers which may see a drop in load diversity for a short time.

13.1.6 Impact on network investment from RETA sites

The majority of RETA sites will connect to the distribution network (rather than the transmission network), therefore it is necessary to analyse whether the existing distribution network to which the site is connecting, can accommodate each RETA site, and if not, what the network upgrades may be required to facilitate the connection at the agreed security level for the site (e.g. N or N-1).

To undertake analysis given the nature of the information available and the complexity of the task necessitates developing a set of assumptions about how the various sites could potentially be accommodated within a network. Exploring these assumptions with the relevant EDB may indicate where opportunities for cost reductions exist. Specifically, process heat users need to discuss the following aspects with EDBs and Transpower (where relevant):

- Confirm the spare capacities of both the GXP and Zone substations[145]. The analysis presented in this report calculated these based on the **publicly disclosed loading and capacity information** in Transpower's 2022 Transmission Planning Report and the EDBs 2023 Asset Management Plans.

144 Transpower's description of a prudent demand forecast is as follows: *'For the TPR we use a 'prudent' demand forecast to recognise the significant risks associated with investing too late to address grid issues. In effect, we add extra demand growth in the first seven years of the forecast to account for potential high levels of growth. After the first seven years we assume expected levels of growth. We determine the amount to add by calculating in our stage 1 models both the expected level of base demand and the 'prudent' 10% probability of exceedance base demand. The ratio of the stage 1 prudent base growth to expected base growth is then used to scale up the final demand from the stage 2 output to give the final 'prudent forecast.'* Transmission Planning Report (2022), page 20.

145 Zone substations are large substations within the distribution network.

- The degree to which the process heat user's demand is **coincident with peak demand on the network**, for the purposes of assessing the amount of spare capacity each site absorbs. More detailed modelling of the pattern of site demand, and potential flexibility in that pattern, versus the timing of (typical) peak loadings on the network, may yield further opportunities to reduce upgrade costs. Further, the opportunity for the site to provide short-term demand response (e.g. by utilising hot water storage to pause boiler operation for a small number of hours) in peak demand situations or following a network fault should be considered, as this may have a material impact on cost.
- **The current level of network security to the site, and whether that should be maintained**. The analysis completed assumes that – for example - if the site currently has (N-1) security, infrastructure upgrades are recommended to maintain this. Ergo's report highlights where upgrade costs could be reduced by allowing for a lower level of security. Adopting a lower level of security should be considered in consultation with Transpower and the EDB, but enabling the site to provide flexibility (i.e. rapid reduction) in demand in response to a failure on a network[146] could save significant amounts of money where expensive upgrades are required to maintain N-1 security.
- The extent to which the upgrades are affected by the decisions of **other process heat sites regarding electrification in a similar part of the network**. There are some parts of the transmission and distribution network where the collective effect of different upgrades and costs would be optimal should a number of sites simultaneously decide to electrify, or – more practically – coordinate their decisions in a way the gives the network owner confidence to invest. In Section 9.4, we consider the collective impact on a GXP should a number of sites choose to electrify.
- The costs associated with **land purchase, easements and consenting for any network upgrades**. These costs are difficult to estimate without undertaking a detailed review of the available land (including a site visit) and the local council rules in relation to electrical infrastructure. For example, the upgrade of existing overhead lines or new lines/cables across private land requires utilities to secure easements to protect their assets. Securing easements can be a very time consuming and costly process. For this reason, the estimates for new electrical circuits generally assume they are installed in road reserve and involve underground cables in urban locations and overhead lines in rural locations. Generally, 110kV and 220kV lines cannot be installed in road reserve due to width requirements. In some locations the width of the road reserve is such that some lines cannot be installed. This issue only becomes transparent after a preliminary line design has been undertaken.
- The estimates of the **time required to execute the network upgrades**. The estimates in the analysis exclude any allowance for consenting and landowner negotiations and are based on Ergo's experience. There is likely to be significant variance depending on the scope of the project and the appetite for expediting.

146 The most common way to do this is a 'Special Protection Scheme' whereby the network owner allows demand to exceed N-1 on the condition that, should a fault occur, demand is quickly (automatically) reduced to the N-1 limit.

13.2 The role of flexibility in managing costs

13.2.1 Why flexibility?

At its simplest, demand-side flexibility is a consumer's ability to be flexible about when they consume electricity. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites may be able to reduce costs and/or generate revenue. This response can be manual (i.e. determined by the consumer in real time) or automated via technology.

In the context of the electrification of process heat, demand side flexibility can have many benefits as outlined below:

- It can help improve the commercial viability and business case of transition projects by reducing upfront capital costs (e.g. optimise the network connection capacity to reduce or prevent a network upgrade).
- It can reduce ongoing electricity procurement costs (e.g. by consuming less at times of high retail rates or network charges, i.e. winter morning and evening peaks).
- It can unlock a new revenue stream to help offset project costs.

13.2.2 How to enable flexibility

The analysis above (in Section 9.3.4) has assessed the cost implications of the electrification of process heat, assuming that:

i. Each site operates in a way that suits its own production schedule; and
ii. The investment in the network is required if the connection of the electrified process causes network security to fall below its current level (i.e. from N-1 to N).

However, control of even very complex production processes can be 'smart', in that the process can respond dynamically to signals from the electricity network and market.

Control technology, automation, predictive algorithms, and communications have evolved over recent years to make these mechanisms smarter and more precise. In the vernacular of the electricity market, it allows consumers of almost any scale to provide 'flexibility services' to network companies and the electricity market, whereby their consumption of electricity adapts continuously, or in specific situations, to what is happening on the network and market. Consumers should be rewarded for providing these flexibility services, either through reduced costs, or through sharing in the benefits captured by EDBs or retailers.

In the context of the electrification of process heat, this creates a number of opportunities for sites to lower their electricity procurement costs, or – in some scenarios – earn additional revenue from the electricity market. Specific opportunities include:

i. Wholesale market response
ii. Minimising retail costs
iii. Dry year response
iv. Minimising network charges
v. Reducing capital costs of connection, and
vi. Other market services, such as Ancillary Services.

More detail about these opportunities is laid out in Appendix 11.1.7.

Of course, altering the production of process heat in order to provide flexibility services i. to v. above has consequences (and potentially cost implications) for the site. Lost production during high priced periods, for example, must be recovered at another time – depending on the nature of the process, the flexibility may be limited.

However, there are a number of ways in which thus flexibility can be enabled. If the site can increase its use of thermal storage (e.g. hot water[147]), this can enable flexibility. Alternatively, a secondary standby fuel could be maintained. Responses could be optimised around production constraints and be automated to reduce labour costs associated with manual decision making.

13.2.3 Potential benefits of flexibility

Enabling flexibility in these ways will incur some costs but may be more than offset by the reduction in electricity consumption costs or the capital contribution to network upgrades. The benefits of enabling flexibility – in terms of reduced consumption costs and capital requirements for network upgrades – could be significant. Further, as the electricity system reduces its use of fossil fuels (coal, natural gas and diesel) in line with emissions prices, and instead builds lower cost wind and solar, the system will require more flexibility from other sources, including consumers. This flexibility could well become a premium product.

There have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 - $300,000[148] per year for every MW of demand that can be reliably moved away from the overall network peak. This may not necessarily reflect the reduction in electricity cost that a RETA site may be able to realise. Further information on estimated electricity cost reductions can be found in Appendix 11.1.8

As previously noted, electricity transmission and distribution networks must be sized to meet peak demand, which may only occur over a few hours of the year. When anticipated growth in peak electricity demand exceeds the existing network capability, costly investments are needed to upgrade the network and/or develop new infrastructure. Process heat users with flexibility that can be enabled in their use of process heat – even for a short period – through the use of interruptible processes or thermal load, may be able to provide highly valuable support to the EDBs and/or Transpower in managing transmission and distribution voltage and thermal constraints affecting the Northland region.

Process heat users are encouraged to seriously consider if they have demand flexibility (including storage solutions such as battery, hot water, ice slurry etc) that they can enable, and if so, how much, and share this information with EDBs and retailers to ensure that they (the process heat user) get the maximum benefit from enabling this.

147 Other methods include ice slurry storage, hot oil storage, steam accumulators.

148 See *Reeve, Stevenson, Comendant (2021), Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf, 1 March 2023; Boston Consulting Group (2022), The Future is Electric.

13.2.4 Who should process heat users discuss flexibility with?

RETA sites should consider their ability to provide flexibility, as well as the potential associated costs and implications.

Once process heat users have assessed the degree to which they can be flexible with their electricity consumption, or the security level they require from their connection, they should approach:

- **EDBs** to assess whether the flexibility can reduce the cost of connecting the new electric boiler to the network. EDB's may also be willing to pay for a process heat user's flexibility in order to defer wider network upgrades (sometimes referred to as a 'non-network alternative').
- **Electricity retailers** to determine the extent to which they will incentivise the process heat user to be flexible in their consumption through the electricity tariff the retailer provides through, e.g. peak and off-peak pricing.
- **Electricity retailers, flexibility service providers[149] and consultancies** to assess the degree to which the site's response to these signals can be automated.

13.2.5 The FlexForum[150]

The FlexForum is a pan-industry collaboration which is striving to help New Zealand households, businesses and communities maximise the value of distributed flexibility. In its Flexibility Plan 1.0, FlexForum outline a set of practical, scalable, and least-regrets steps that should achieve a significant increase in consumers' use of flexibility. A critical component in the Flexibility Plan is 'learning by doing' – supporting organisations (such as process heat users) piloting and trialling flexibility.

13.2.6 Value of flexibility

At its simplest, demand-side flexibility is a consumer's ability to be flexible about when they consume electricity. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites may be able to reduce costs and/or generate revenue. This response can be manual (i.e. determined by the consumer in real time) or automated via technology.

In fact, some of this technology has existed for decades – for example, the ripple relays that allow domestic hot water elements to be switched off, or frequency relays that allow large industrial processes to participate in the instantaneous reserve market[151]. More recently, though, the control technology, automation, predictive algorithms, and communications have evolved to make these mechanisms smarter and more precise. In the vernacular of the electricity market, it allows consumers of almost any scale to provide 'flexibility services' to network companies and the electricity market, whereby their consumption of electricity adapts continuously, or in specific situations, to what is happening on the network and market.

149 Examples of flexibility providers include Enel X and Simply Energy.

150 See https://www.araake.co.nz/projects/flexforum/

151 This is part of New Zealand's wholesale market design, whereby large loads and generation are paid to be on standby if a large system component fails, thus causing frequency to fall.

In the context of the electrification of process heat, this creates a number of opportunities for sites to lower their electricity procurement costs, or – in some scenarios – earn additional revenue from the electricity market. Specific opportunities include:

i. **Wholesale market response** – Section 9.2.1 outlined how the wholesale market is dynamically adjusting to supply and demand conditions in real time, and thus wholesale prices are constantly changing. Sites that choose to be exposed to this wholesale price and that can respond to these prices dynamically will lower their overall procurement cost by consuming less when prices are high, and more when prices are low.

ii. **Minimising retail costs** – Section 9.2.3 outlined how sites that choose to face a more stable retail tariff (rather than direct exposure to wholesale prices) will likely be provided with a set of 'shaped' prices that (at the very least) reflect time of year, weekdays vs other days, and day versus night (see Figure 52). Some pricing arrangements may have more granular prices (e.g. different prices for each four-hour 'block' of the day). This provides incentives for site operators to schedule production in a more predictable way (compared with a volatile wholesale price), again lowering electricity procurement costs by scheduling production away from high priced periods.

iii. **Dry year response** – It is relatively well known that, due to the dominance of hydro in New Zealand's electricity system, the system occasionally experiences 'dry years' where low inflows persist for weeks and potentially months. This can raise wholesale market prices significantly for a prolonged period, and electricity retailers may be willing to incentivise consumers to reduce demand for this period. This obviously would have significant consequences for manufacturing processes, although sites with dual-fuel capability (e.g. electricity and coal) could switch from electricity to coal during these periods with little impact on their operations.

iv. **Minimising network charges** – As discussed in Section 9.2.4, EDBs may price some component of network charges based on the consumption of the site at peak network demand times (e.g. weekday morning and evening peaks). By reducing demand at these times, network charges may be able to be reduced.

v. **Reducing capital costs of connection** – Similarly, when considering the capital cost associated with accommodating newly electrified processes, Section 9.3 outlined that a key factor is the current spare capacity at peak times in the existing network. Flexibility in electricity consumption can potentially reduce the cost of network upgrades in two different ways:

   - Ensuring demand from the site is reliably[152] lower during the times of peak network demand (when spare capacity is at its lowest), thus reducing the amount of network investment required from the network company.
   - Allowing the site's demand to be reliably interrupted should a part of the network fail (known as a 'Special Protection Scheme'). The network company may, based on a risk assessment, allow network security to drop from N-1 to N-0.5, or N at peak times (see Section 9.3.2), thus requiring a lower level of investment in network upgrades, on the understanding that should a component of the network fail , the site will immediately[153] reduce demand so that the network remains stable and thus doesn't affect other consumers connected to the network.

152 This would have to be sufficiently reliable to give the network company the confidence to scale back its investment.

153 Depending on the nature of the security limitation, this may be required to be instantaneous, or may permit up to 15 minutes for the response to occur.

vi. **Other market services** – Finally, there are a number of 'ancillary services' that Transpower, as the electricity 'system operator' must procure which help it manage the whole system's stability and resilience. A reliably responsive demand site may be able to provide services into these markets and earn revenue from them. Participation can be as little as one to two response events per year that require a load drop of only a number of minutes. We note that the industry is currently discussing how these services may evolve as the amount of intermittent wind and solar increases on the system, including new types of ancillary services that may arise[154].

13.2.7 Flexibility benefits

Enabling flexibility in these ways will increase cost but may be more than offset by the reduction in electricity costs or the capital contribution to network upgrades. The benefits of enabling flexibility – in terms of reduced consumption costs and capital requirements for network upgrades – could be significant. Further, as the electricity system reduces its use of fossil fuels (coal, natural gas, and diesel) in line with emissions prices, and instead builds lower cost wind and solar, the system will require more flexibility from other sources, including consumers. This flexibility could well become a premium product.

There have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 - $300,000[155] per year for every MW of demand that can be reliably moved away from the overall network peak.

This may not necessarily reflect the reduction in electricity cost that a RETA site may be able to realise. However, the Electricity Authority's independent Market Development Advisory Group (MDAG) estimated the electricity cost reductions that an existing process heat site could realise in a future system with a very high degree of renewables[156]. Notably:

- It estimated that a process heat site using expanded hot water storage could save between 8% and 18% of its electricity procurement costs if it responded dynamically to wholesale prices (option (i) above).
- It also estimated that a process heat site that maintained an additional standby supply of fuel and boiler that could substitute for its electric boiler in a dry year could save around 16% of its electricity procurement costs (again if it were exposed to wholesale prices).

These figures do not include any benefits associated with reduced network charges, or the capital costs of upgrades to the distribution network in order to facilitate an increase in electricity demand, if this process heat demand had been new (i.e. (iv) and (v) above). These would be in addition to the savings noted above.

[154] See https://www.araake.co.nz/projects/flexforum/. Note that, in some situations, process heat organisations may be able to receive revenue for a number of demand side flexibility services.

[155] See *Reeve, Stevenson, Comendant (2021), Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf; Orion (2023), 1 March 2023; Boston Consulting Group (2022), *The Future is Electric*.

[156] See https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-in-a-renewables-based-electricity-system/, specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

We note that, while MDAG's simulations assumed the process heat site was exposed to wholesale prices, this need not be the case for savings to be realised. If the site purchases power through a retailer, then the retailer would save the wholesale costs if the site responded and should share those savings with the site. Of course, this requires an arrangement between the retailer and the site as to when the alternative fuel needed to be switched in, how much notice was given, and what savings would be shared.

MDAG's figures do not include any benefits associated with reduced network charges, or the capital costs of upgrades to the distribution network in order to facilitate new process heat demand had they been new (i.e. iv. and v. above).

13.3 Overview of the Transmission Pricing Methodology (TPM)

In essence, the TPM attempts to identify, amongst its customers (distributors, generators, direct connects), who the beneficiaries are of each of Transpower's assets, and allocate charges to those beneficiaries. This is a similar intent to the pricing methodologies of EDBs discussed in Section 9.2.4 above.

There are three basic components of the new TPM, plus a range of adjustments that are outlined further below. The three components are:

i. **Connection charges** – There are some assets owned by Transpower which are only there for the benefit of a very small number of users. These are known as 'connection assets', as they tend to exist solely to connect an EDB's network, and/or a large industrial consumer, and/or a generator, to the national grid. In these situations, Transpower's costs – capital returns and operating expenses – are shared amongst that very small group of users in a relatively simple way.

ii. **Benefit-based charges (BBC)** – These charges relate to specific investments where the beneficiary identification is more complex than for connection assets[157], but the beneficiaries have been established by the Authority (and allocations of charges calculated accordingly). This analysis will occur for grid investments going forward, but also includes seven relatively recent grid upgrades that were approved by a regulator under the current market design, and hence were subject to a range of cost-benefit assessments. Should grid upgrades occur in the Northland region (see Section 9.3), the associated transmission charges would be calculated in accordance with the BBC methodology. It is difficult to estimate now what the likely quantum of charges would be, as the Authority won't determine the allocations amongst the various beneficiaries until the investment is formally considered.

iii. **Residual charges** – For the remainder of the existing transmission network not covered by BBC charges[158], it is too difficult to identify specific beneficiaries of each asset. Charges for these network assets are referred to as the residual charge (RC) and are spread across all loads (EDBs and grid connected industrial consumers). Generators don't pay the RC. RC is principally spread across loads in proportion to their anytime maximum demand. An important consideration for new grid-connected electricity demands, such as that arising from electrification of RETA process heat sites, is that they do not receive an RC charge for the first four years of operation; after that, the RC allocation steps up linearly over a four-year period. As a result, these new grid-connected demands (which include demands from distribution networks) do not face their full RC allocation for eight years. Equally, RCs for grid-connected demands take eight years to reduce to the new level.

The intent and essence of the three types of charges may appear relatively straightforward, but the methods by which they will be determined (especially the BBC) is complex. To aid understanding, we have included a worked example for a stylised process heat consumer in Section 11.2.2 of this report.

157 These more complex assets are referred to as 'interconnection assets', reflecting the fact that the tend to be part of the meshed grid, and the use of these assets can relate to a wide range of customers at different times. The residual charge also relates to interconnection assets.

158 Pre-2019 grid assets, not including the seven relatively recent grid upgrades listed in Appendix A of the TPM.

Further, the Electricity Authority has included an additional set of mechanisms in the TPM that anticipate, and attempt to correct for, some undesirable outcomes that could occur with a customer's transmission charges. These include:

- **Transitional cap** – A transitional cap on prices to avoid 'rate shock'. The cap is inflation adjusted; therefore, with prevailing rates of inflation in early 2023, the cap is unlikely to have any material effect on charges.
- **Adjustments to charges** – Adjustments for things like new connections to the transmission network, customers disconnecting from the transmission network, and substantial changes in circumstance leading to substantial changes in consumption (increased or decreased). This is especially important for the connection of new electrode boilers, which – as they are replacing coal – would in some cases lead to material increases in demand taken by EDBs from Transpower's grid. Equally, some large sites may decide, upon electrification, to switch from being connected to the distribution network to direct grid connection – this would cause a drop in the EDB's peak demand.
- **Prudent discounts** – The TPM provides for discounting transmission charges where, based on an economic framework, a customer is 'overcharged' as a result of the TPM. Overcharging has a specific meaning, namely that the customer's TPM charges would lead them to inefficiently bypass the grid e.g. by building a self-supply and disconnecting from the grid, or building a line to a different part of the grid. Transpower has published a draft prudent discount manual. There is a significant amount of analysis that is required to prove that an individual customer's TPM charges are a genuine case of 'overcharging'.

We note that – since Transpower is entitled to recover a fixed amount of revenue from its customers – any reduction to one set of Transpower's customers, using the mechanisms above, results in an increase in charges to Transpower's other customers.

13.3.1 What does the TPM mean for RETA sites?

As noted above, our various references to 'customers' of Transpower, and payers of transmission charges, relate to EDBs, generators and grid connected industrial consumers. The majority of RETA participants do not fall into these categories, as they are connected to a local EDB's network, rather than Transpower's.

EDBs, however, will pass through transmission charges to their customers (i.e. electricity consumers). The exact mechanism by which each EDB 'repackages' TPM charges will vary across the country, but the Electricity Authority has published guidance on how they expect EDBs to do this.

Fundamentally, the Electricity Authority expects that an EDB will pass the TPM charges on consistently with how they are derived in the TPM:

- The BBC and RC to be passed on as a daily fixed charge.
- Connection charges will probably be on-charged substantially as done previously.

The EDBs will need to do some form of categorisation and averaging to allocate the transmission charges. The methods used in the TPM for categorising, averaging, and lagging measures of 'usage'[159] of the grid give EDBs some discretion to how costs will fall. For example, an averaging method based on energy consumption will tend to move charges from residential towards industrial consumers and vice versa for averaging based on peak demand[160]. EDBs may also base charges on historical periods that, in their view, are a better reflection of the party's consumption that created the need for transmission capacity in the first place.

[159] For example energy usage over time, or peak demand.

[160] Residential demand tends to be more 'peaky' than many forms of non-residential demand.

EDBs have published their pricing schedules for the 2023/24 pricing year – the first year that the new TPM applies. However, even without any new grid investments, we strongly caution against using these figures as a guide. Transpower's indicative transmission charges for 2023/24 show that the majority of charges accruing to EDBs are the residual charges. As outlined above, the intent of these charges is to recover the sunk costs of grid where individual beneficiaries haven't been identified. As such, they are intended to be unavoidable charges which should not change marginal operating or investment decisions. Defining these as per-MW charges accruing to newly electrified load will tend to overstate their magnitude, depending on the degree to which EDBs rebalance charges across their customer bases.

13.3.2 A worked TPM example

For this example, we are using a practical example based on a stylised. While the example is based on the process heat user, the results should be treated as indicative only for the purpose of illustrating the transmission charges.

The process heat user has an existing demand connected to the EDB, who in turn connect the process heat user to the grid at one of Transpower's GXPs. For the avoidance of doubt, we are only looking at the transmission charges that would be applicable to the process heat user under the new TPM, not the distribution charges. Note also that there may be some averaging of charges that means that the EDB does not pass on the charges as outlined here.

The process heat user is also investigating replacing its coal boiler with an electrode boiler, which will substantially increase both its peak demand and total energy consumption.

We are only going to evaluate the three main components of the transmission charges, CC, BBC, and RC. As we discuss above there are a number of smaller adjustments that might also apply to ensure that Transpower's costs are recovered, we cannot anticipate all of these. The one that we would have had to adjust for, the transitional price cap, is inflation adjusted but, with very high inflation, the cap now barely applies.

We look at each charge individually for the starting point of how the new charges would apply to the process heat user's current load and then how those charges would change for the electrode boiler investment. We also estimate future charges for both scenarios. The initial prices are based on Transpower's Excel spreadsheet 'TPM indicative pricing model August 2022'.

13.3.2.1 Connection charges

The GXP is a grid node, not a connection node, and there is no Transpower spur line to the EDB. However, there is equipment at the GXP substation that is only there to connect the EDB to the grid. In addition to circuit breakers and other switchgear this includes two 220/33kV transformers as the GXP grid bus is 220,000 volts while the EDB takes supply at 33,000 volts. The annualised cost of these connection assets is assessed as $457k for the 2023/2024 pricing year. As the EDB is the only customer at the GXP these connection costs are all allocated to the EDB.

Where there are multiple customers on one connection then connection charges are allocated to customers on the basis of their Anytime Maximum Demand (AMD) to the total of all customer's AMDs. This is a way in which the EDB could allocate connection charges to their customers that is consistent with the TPM. We can't know what the total of all AMDs within the EDB's network is (behind the GXP) and so we will simply assume that the AMD of the combined network is the total of all AMD.[161] This gives a worse case allocation for the process heat user. AMD is the average of the twelve highest half-hour peaks in the given year or other time period. We have assessed the AMD for the process heat user based on data provided to us, which gives 18.1 MW. We assume that the process heat user peak demand will remain constant unless they physically invest in new plant. For the GXP demand we use the peak demand forecast from Transpower's 'Transmission Planning Report 2021'.

This gives a forecast of connection charges for the process heat user's current demand in Table 18.

Table 18 – Forecast connection charges for the process heat user current demand

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	110	113	115	118	120	122	125	127	129
Process heat user AMD	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M

To assess the increase in charges for the addition of the electrode boiler we add 24MW to the process heat user's current AMD and to the EDB AMD but make no other alterations. Again, this is the worst case for the process heat user and gives the connection charges forecast in Table 19.

Table 19 – Forecast connection charges for the process heat user demand and new boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	134	137	139	142	144	146	149	151	153
Process heat user AMD	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
Allocation	31.4%	30.7%	30.3%	29.7%	29.2%	28.8%	28.3%	27.9%	27.5%
Process heat user CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M

[161] The network's AMD can be different to the sum of customers AMD as customer's AMD can occur at different times.

13.3.2.2 Benefit-based charges

The Benefit-based Investments (BBIs) that are allocated to the EDB at the GXP are all ‘TPM Appendix A’ BBIs. This means that they are the pre-2019 investments chosen and assessed by the Electricity Authority for the guidelines given to Transpower. As the Electricity Authority had already determined these allocations, Transpower was instructed to use these allocations, which are attached in the TPM as Appendix A.

The investments and allocations that apply for the GXP are given in Table 20.

Table 20 – Benefit-based investment projects and allocations for the GXP

BBI	Allocation
Bunnythrope Haywards	5.34%
HVDC	1.38%
LSI Reliability	10.57%
LSI Renewables	6.33%
NIGU	0.38%
UNIDRS	0.38%
Wairakei Ring	0.35%

Once these allocations have been made to the recovery costs of the above projects then the BBC charges that apply to the EDB for the GXP for the 2023/2024 pricing year are $1.07M.

When it comes to allocating the process heat user a share of these charges, the EDB could consider three methods that are consistent with the TPM. These methods are:

- Attempt to recreate the Authority’s original method for allocation.
- Attempt to apply the standard method from the TPM.
- Apply the simple method from the TPM.

It would not be feasible for a distributor to use the first two methods. They don’t have the input information or models to replicate the results. The simple method models the beneficiaries by regions of the transmission network and then allocates these benefits to connection locations using Intra-Regional Allocators (IRA). The calculation method for IRAs is the most practical method, consistent with the TPM, for allocating BBIs.

There is a further complication, though. Different IRA calculations apply according to the nature of the investments. We think it unlikely that a distributor's methodology would be considered inconsistent with the TPM by simply picking one of the methods to apply to the total BBC. Both methods use the same calculation period being three years of data lagged by two years, i.e. n[162]-4 to n-2 inclusive, in this case 2018 to 2021. The allocation would then be based either on peak coincident demand over that period or total consumption over that period. the process heat user has a very low-capacity factor for an industrial user at 32%. This means that the two approaches yield very different allocations. Using peak coincident demand (using our assumptions from above) would give 16.5% and using consumption would give 3.6%. Given the peaking requirements for the process heat user and that most of the TPM Appendix A BBIs could be described as investments to meet peak demand, we think that the EDB might use 16.5%. This would give the process heat user a starting BBC allocation of $175k (i.e. prior to the 25MW increase from the new electrode boiler).

As TPM Appendix A BBIs are fixed allocations then the EDB is likely to treat the starting allocation for the process heat user as a fixed allocation. This gives the outcome in Table 21.

Table 21 – Worst case benefit-based charge allocation to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M

TPM Appendix A BBIs are fixed allocations but do change for adjustments made for new customers, exiting customers, and substantial changes in consumption. We can't possibly predict what these changes might be and so we assume that these charges apply for the foreseeable future. The adjustments made for the new electrode boiler at the process heat user will help illustrate what could happen.

The GXP's BBC will also change if they are allocated charges for new BBIs. Again, we will not attempt to predict what these are and how they would be allocated but we will illustrate the potential impact of an imaginary investment on the charges for illustrative purposes.

The definitions for the events that cause an adjustment under the BBC are confusing. On consulting the Electricity Authority's original decision paper on the intent of the adjustments we believe that the proposed electrode boiler would be considered a 'Benefit-based Charge Adjustment Event: Large Plant Connected or Disconnected'. This event requires the large plant connection to be treated as if it's a new customer at the connection location but with the BBI allocation added to the relevant transmission customer, i.e. the EDB. Then all customers allocations must be reduced by a factor to keep the adjustment revenue neutral. The adjustment formulae for calculating the adjustment seems to have a logic error in that the same term used for the adjustment factor solution is used as an input to a formula where the solution is used as an input to the adjustment formula, i.e. prima facie a circular reference.

162 Here, n refers to the current year.

The formulae gross up the BBC at the connecting location based on the consumption assessed by Transpower against the same capacity period as residual charges 2014-2017 inclusive. As the new electrode boiler is going to increase the consumption at the GXP by 138GWh and the 2014-2017 average consumption is 452GWh, then the gross increase in charges at the GXP will be 30.5%, which is $325k for the 2023/2024 pricing year. All customers who pay for the BBIs relevant to the GXP get a slight reduction in charges to ensure revenue neutrality. However, as the change in charges is $325k in a set of projects with annual cost of $211M then the adjustment is negligible.

It is worth noting that, if the BBC for the GXP had included post-2019 BBIs the calculation of the increase in charges would have been more complicated. Although, it is also worth noting that the significant drivers on the BBC are two of the TPM Appendix A BBIs, the HVDC ($116M of BBC) and North Island Grid Upgrade (NIGU – the new Pakuranga to Whakamaru 400/220kV line - $68M).

Once the EDB's charge have been adjusted for the new electrode boiler then this becomes a new fixed allocation of charges. If the new boiler's consumption proves to be more than 25% higher, then it might trigger a 'Benefit-based Charge Adjustment Event: Substantial Sustained Increase' event. There is no commensurate sustained decrease provision.

As the increase in the EDB's charges is attributable to the process heat user if the electrode boiler goes ahead then the resulting charges are shown in Table 22.

Table 22 – Benefit-based charges for the process heat user with electrode boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
+ boilers	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M
Total	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M

We have seen above that the addition of other new connections, unless very large or there are a large number, can make little difference to BBC.

To illustrate how new BBIs might affect the process heat user's charges we take the example of a potential upgrade of the HVDC (say a fourth cable across the Cook Strait). If this project were to cost $80M, which gives a very approximate $5M in additional costs per year, and the benefits flowed through as per the TPM Appendix A HVDC allocations, then the process heat user would attract a further $25k per year in BBC.

13.3.2.3 Residual charges

Residual charges are the largest charges that are passed through. They are passed through initially as lagged peak charges and then adjusted based on lagged consumption. The RC assessed for the EDB for the 2023/2024 pricing year are $4.6M.

The AMD that is applied for $AMDR_{baseline}$[163] is different to the one that applies for CC. However, we will assume the same allocation factor for AMD applies for the $AMDR_{baseline}$, i.e. that the process heat user will get 16.5% of the RC. If we assume there is no significant difference in total EDB consumption, then there will be no significant difference in the allocation of RC to the process heat user. In practice, this will depend on many factors including changes in consumption within the GXP network and elsewhere. This gives RC for the process heat user as shown in Table 23.

Table 23 – Residual charges for the process heat user without boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M

If the boiler is added there will be no immediate impact on the EDB's RC due to the adjustment factor being based on lagged consumption. After four years then consumption is based on four years of average consumption lagged by four years. Based on the assumption that the new electrode boiler adds 138 GWh per year starting in the 2023/2024 pricing year, then the adjustment in charges is shown in Table 24.

Table 24 – Residual charges for the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Adjustment factor	1.00	1.00	1.00	1.00	1.00	1.08	1.16	1.24	1.32
EDB charges	$4.60M	$4.60M	$4.60M	$4.60M	$4.60M	$4.97M	$5.35M	$5.72M	$6.09M
Increase for boiler	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.37M	$0.75M	$1.12M	$1.49M
Process heat user with boiler	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.50M	$1.88M	$2.25M

The charges reach their fully adjusted value in 2031.

163 Anytime Maximum Demand for residual charges baseline.

13.3.2.4 Summary of charges

Table 25 summarises the outputs of Table 20, Table 23, and Table 25 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 25 – Forecast allocation of transmission charges to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Connection charges	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M
Benefit-based charges	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
Residual charges	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M
Total	**$1.02M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.00M**

Table 26 summarises the outputs of the three tables above to give the forecast allocation of transmission charges to the process heat user with the proposed electrode boiler.

Table 26 – Forecast allocation of charges to the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Connection charges	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M
Benefit-based charges	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
Residual charges	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.5M	$1.88M	$2.25M
Total	**$1.40M**	**$1.40M**	**$1.40M**	**$1.40M**	**$1.39M**	**$1.76M**	**$2.13M**	**$2.51M**	**$2.88M**
Increase	**$0.39M**	**$0.40M**	**$0.40M**	**$0.40M**	**$0.39M**	**$0.76M**	**$1.13M**	**$1.51M**	**$1.89M**

Table 26 also shows the increase in transmission charges after the boiler is installed. The charges are fully increased by 2031 to $2.88M, a $1.89M increase from what would happen without the boiler (ceteris paribus). Calculating the present value of 10 years (at 8% discount rate) of increased transmission charges gives $5.53M.

Robertson Island, Northland, New Zealand. Credit – Northland NZ.

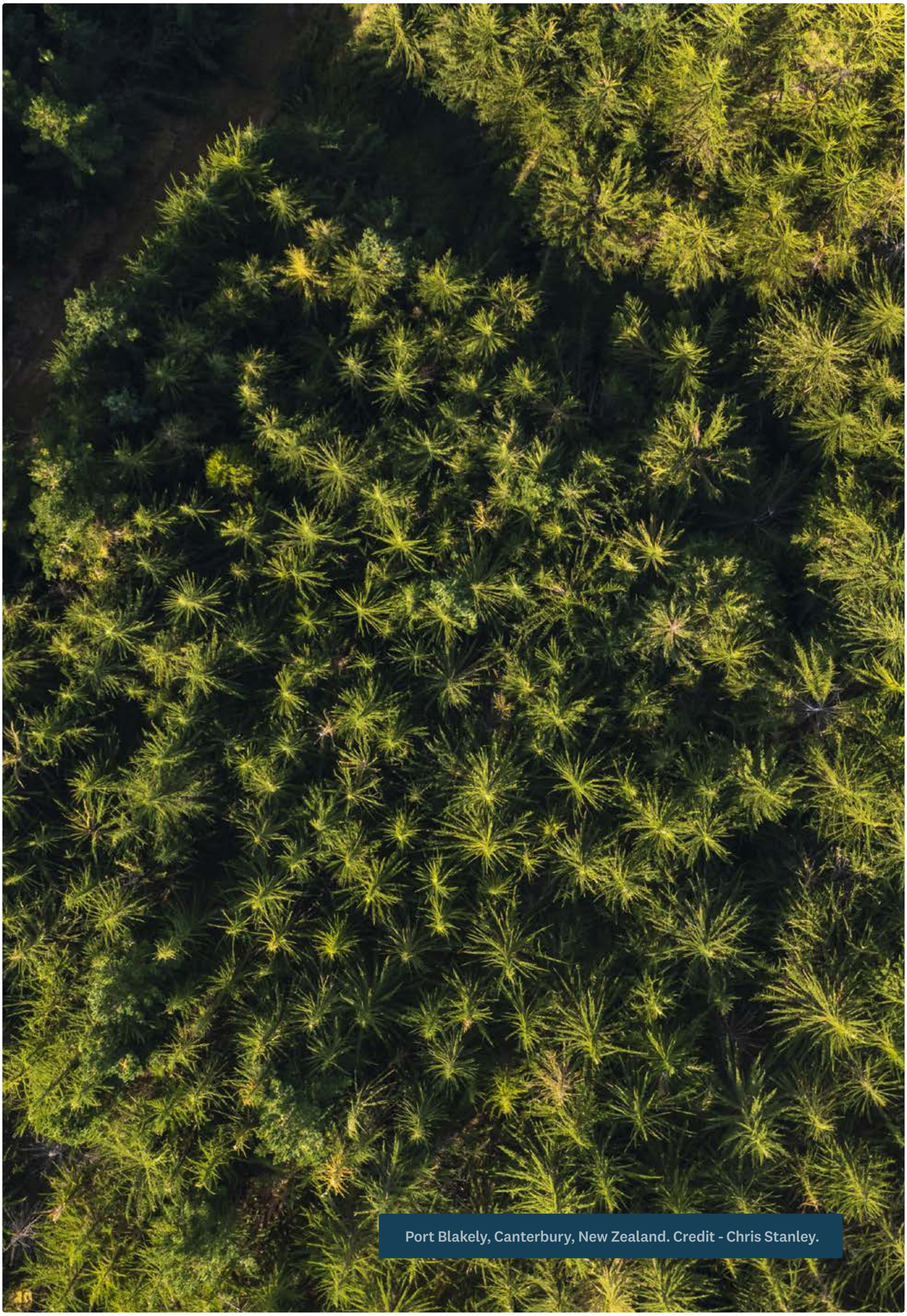
14 Appendix D: Additional information on bioenergy

Wood processing residues are generally categorised as:

- **Sawdust** is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.
- **Bark** is mostly created at the port when handling, storing, and loading logs but small volumes are also available from processors.
- **Woodchip** is created onsite from all viable offcuts and is sold for landscaping, animal bedding or to MDF.
- **Shavings** are created when dressing the timber which creates a finished product smooth and clean. Shavings are usually created after the timber has been dried so it is light and dry and is good boiler fuel.
- **Post peelings** are the residues created from making round posts (fencing, poles, lamppost) and are thin and long in shape making them difficult to handle. Additional processing may be necessary to create a more uniform product for bioenergy.
- **Slabwood** is produced from the offcuts of milling and sold as firewood.
- **Dockings** are lumber offcuts and may be green (which will normally be fed back into the chipper), or from a dry mill in which case they may be sent to a boiler, chipped, or sold as firewood.

Harvesting residues are categorised as:

- **Billets** are shorter pulp logs (minimum length 1.8m).
- **Binwood** is shorter than billets and is easily accessible residues that are collected by a truck with a bin.
- **Salvage wood** is described as salvageable biomass that is collected using a 'log reach excavator'.
- **Cutover** refers to residues from stems and branches left in the area that has recently been felled and cleared and is not as easy to access. This volume is technically recoverable but at a higher cost due to the additional effort required.



Port Blakely, Canterbury, New Zealand. Credit - Chris Stanley.

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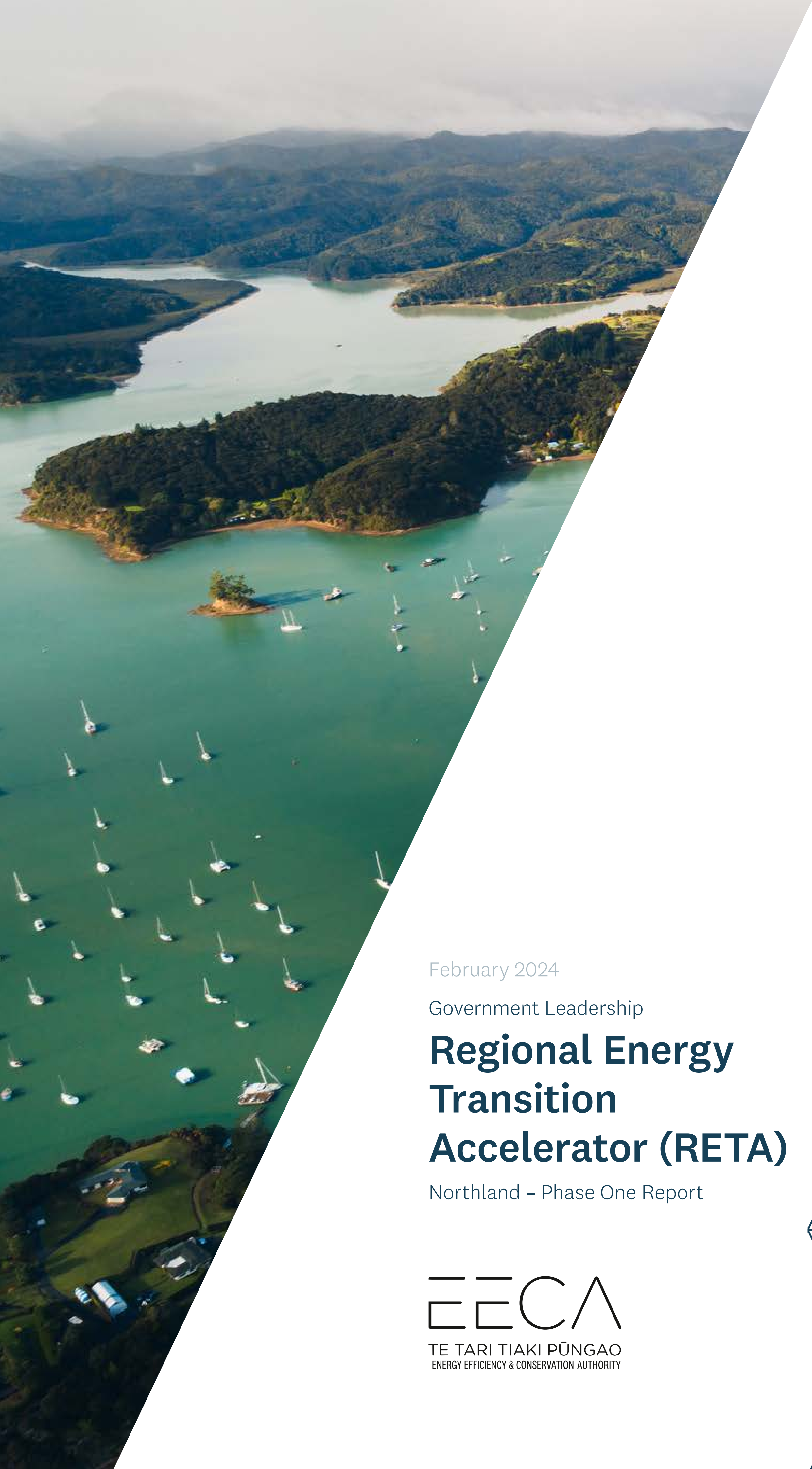
Whangārei Heads, Northland, New Zealand. Credit – Northland NZ



February 2024

Government Leadership

Regional Energy Transition Accelerator (RETA)

Northland – Phase One Report

EECA
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